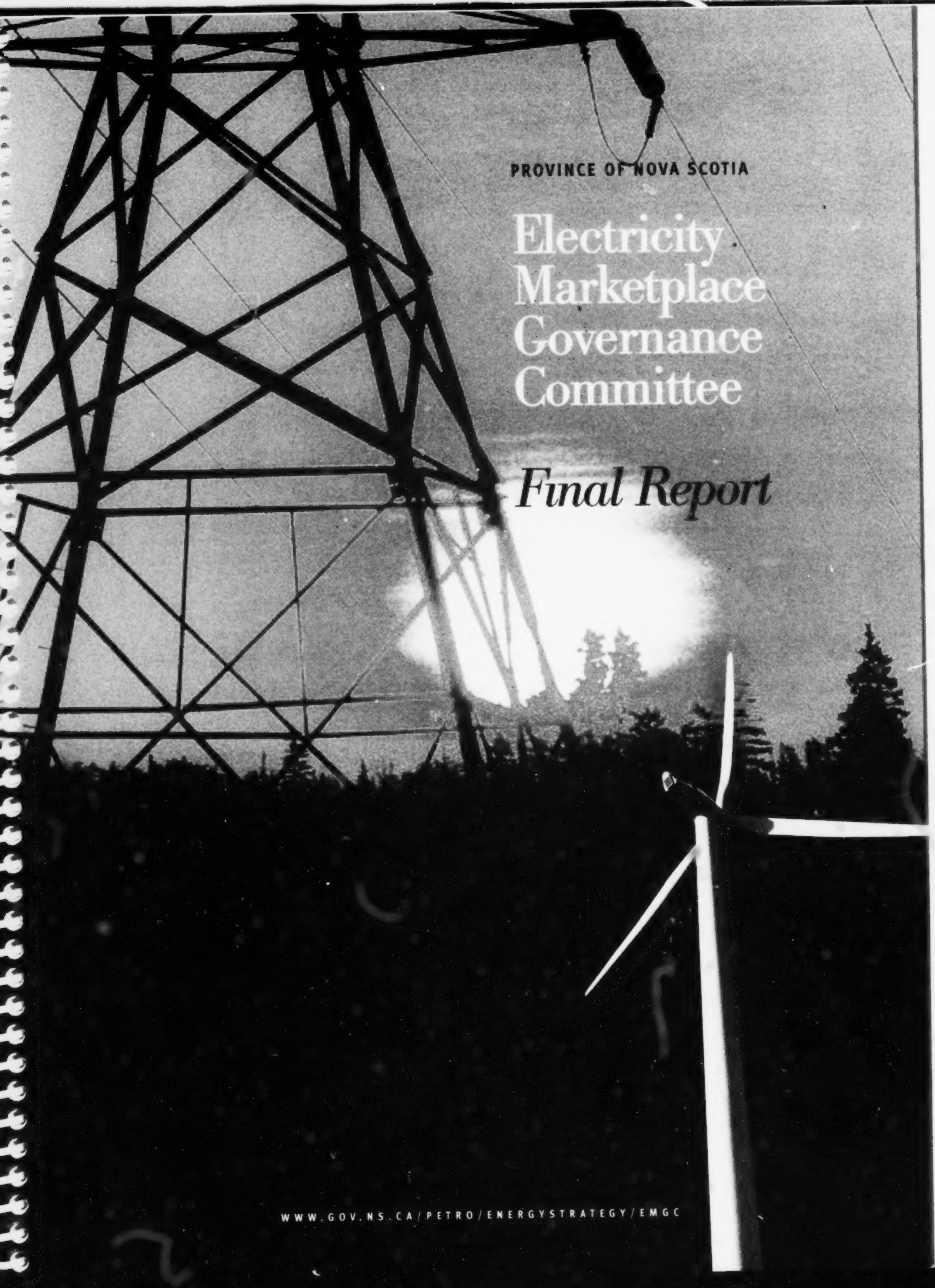

PROVINCE OF NOVA SCOTIA

Electricity Marketplace Governance Committee

Final Report

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Executive Summary

This is the Final Report of the Nova Scotia Electricity Marketplace Governance Committee (EMGC). The EMGC, appointed by the Government of Nova Scotia as a direct outcome of the release of its new *Energy Strategy*, began its deliberations in June 2002. The committee was asked to provide specific recommendations to the Minister of Energy in order to implement the electricity elements in the *Strategy*.

Overview of the EMGC Deliberations and Recommendations

Over the course of its existence, the EMGC considered more than a dozen substantive issues, leading to 89 recommendations. The Committee was aware throughout, of the size, geographic location, physical nature and uniqueness of the Nova Scotia electricity system. The Committee is confident that it has recommended a basic market design and market model that are well suited to achieve the objectives of the *Energy Strategy* within a Nova Scotia context, as well as to provide an appropriate foundation for future flexibility and evolutionary change.

The EMGC paid considerable attention to the issue of how best to promote more desirable forms of generation, including cogeneration and generation from renewable resources. Recommendations on these topics would create a system of mandatory and voluntary approaches that would be designed to achieve these goals.

Many of the remaining recommendations concern the creation of structures that will be required to implement the new electricity market in Nova Scotia.

Market Scope and Basic Market Model

"Market scope" is the fraction of total demand that is open to competition. The *Energy Strategy* committed only to allowing Nova Scotia's wholesale customers – the six municipal utilities – to buy electricity from a competitive supplier. This would make the initial market scope about 1.6% of the peak demand for electricity, or slightly less than 50 MW. The EMGC considered recommending a larger market opening, as for example, broadening competition to include the largest industrial customers.

"Market model" embodies the process whereby electricity trading will take place. The EMGC considered market scope and market model to be closely related decisions because a limited market size might permit a choice in favor of a simpler and cheaper market model.

Deciding on the appropriate market scope required a tradeoff between competing objectives. Choosing the broader market offered the greater likelihood of new competitors entering the market and forcing generation costs down. Alternatively, a less desirable outcome might be the development of more costly market infrastructure and increased exposure by consumers to price volatility in the market. That volatility, in the presence of market power, more than likely would not produce lower prices for consumers.

Reflecting on these tradeoffs, the EMGC concluded that it did not have sufficient information to make a truly informed choice. Therefore, the Committee accepted the limited market scope described in the *Energy Strategy*, while recommending that the government fund a very specific and narrowly defined study of the likely costs and benefits of broader competition in the Nova Scotia electricity market. It also recommended a re-visitation to the market scope issue when additional information became available.

Consistent with the market scope decision, the EMGC opted for a bilateral contract market. In this model market participants contract with each other while a system operator schedules those transactions and dispatches the electrical system.

Planning Responsibility

The *Energy Strategy* indicated that the Nova Scotia Utilities and Review Board (UARB) should have new responsibilities regarding the addition of new generation capacity. The EMGC, in order to implement this process, recommended that NSPI file its 10-year supply and demand plans annually with the UARB, which in turn would open a period in which comment could be filed by interested parties.

Under the recommended system, following a forecast of a supply shortfall, the UARB would oversee a competitive process to acquire either new capacity or demand side management. NSPI, because of its obligation to supply, would be required to tender a bid. At the conclusion of this process, the resulting cost would be added to NSPI's revenue requirement and be recovered from all of its electricity-buying customers.

Transmission Issues

The EMGC discussed several issues relevant to transmission in Nova Scotia. These included: ensuring open transmission access; the nature of the transmission tariff; services to be offered; design of the tariff; congestion management; functions of the system operator; and metering.

The transmission system is the essential transportation channel for electricity. Competitors to NSPI require assurances that they will not be discriminated against, given that the essential system is owned by an affiliate of the incumbent generator (integrated utility with functional unbundling). So, the EMGC recommended that NSPI develop a non-discriminatory transmission tariff. It also recommended that the transmission tariff be implemented to meet the needs of Nova Scotia transmission users, without incurring unnecessary expense. Additional recommendations clarified transmission definitions and charge determinants.

Companies who supply some of their own electricity with their own generation now pay transmission charges for that load only when their generation is not running. To help ease their transition to the new transmission tariff, the EMAC recommended that the charge basis for existing self generation customers would be based on hourly net non coincident peak load.

A transmission system is congested when various constraints force more expensive generation to be used because cheaper sources cannot reach the load. The EMGC recommended that all transmission users share congestion costs. Transmission service can be firm or non-firm; the EMGC recommended that current firm-service customers continue to have rights to firm service. The EMGC recommended that rights be created for service on the interties to New Brunswick, with the expectation that the forthcoming transmission tariff will identify how those rights will be allocated.

To facilitate a bilateral contract market, a system operator must schedule transactions and provide ancillary services. Given the size and structure of the Nova Scotia market, the logical entity to assume the role of system operator is the current transmission function within NSPI, functionally unbundled from NSPI. Finally, tariff unbundling may require higher metering standards, and the Committee recommended that they be improved over time.

Promoting Generation from Renewables

The *Energy Strategy* declared that renewable sources would play an increasingly important role in electricity generation in Nova Scotia. The EMGC identified some barriers to achieving that goal, and recommended policies both to remove barriers and to ensure increased adoption of renewables.

A policy promoting renewables cannot function without an operational definition. The EMGC accepted the EcoLogo® definition of renewable low-impact electricity, but also suggested the definition should be modified to include tidal and wave power.

A renewable portfolio standard (RPS), which requires that a specific (and growing) fraction of total electricity supply come from renewable resources, is a commonly used policy tool. The EMGC recommended that Nova Scotia adopt an RPS at the conclusion of the current NSPI voluntary program, mandating that the share of new renewables (post 2001) in electricity supply increase to 5% by 2010. The EMGC made several recommendations relating to the design of the RPS and the way that responsible entities could meet it, but recognized the need for a further process of definition before the RPS is implemented.

An RPS is mandatory and it spreads additional costs, if any, over the entire rate base. The EMGC recommended that all sellers of electricity from such resources have access to all consumers, but that they should be licensed by the UARB to prevent abusive sales tactics.

Another way to promote generation from renewable resources is through net metering. This allows individuals who possess small renewable generation systems (less than 100 kilowatts) to let their meters run backwards when their generation exceeds their consumption. The EMGC made several recommendations to ensure that net metering is available on reasonable terms.

Promoting Cogeneration

The *Energy Strategy* identified cogeneration, the simultaneous production of electricity and usable heat, as a preferred form of generation. However, it did not specify policies that would promote cogeneration relative to other forms of generation.

Cogeneration can benefit from improved market access because the heat and electricity loads of the cogeneration installation typically do not match, so the generator has excess electricity to sell. Being able to sell it directly to an end use customer, in addition to the incumbent utility, can be a key factor in making a new cogeneration facility economic.

The EMGC felt it important to recommend policies to promote cogeneration. A subcommittee of the EMGC met with a group of interested stakeholders to discuss several issues related to this topic; thegroup then made some recommendations to the Committee. Areas discussed by the EMGC included consideration of the need for new capacity and the role of cogeneration in meeting it, definition of cogeneration for policy purposes, and market access for sellers of electricity from cogeneration facilities.

NSPI provided the committee with information showing the expected need for new supply over time. New cogeneration that helped to meet that need would not create any stranded cost.

If electricity from cogeneration facilities is to receive special policy treatment then an operational definition is essential. The EMGC devoted considerable attention to such a definition and carefully considered recommendations from the sub-committee. The resultant definition refers both to federal policy and to views of the sub-committee.

The EMGC made several recommendations to ensure market access for sellers of generation from new cogeneration facilities in Nova Scotia. These included direct access to large industrial customers connected to the transmission grid, contract access to all customers except for the smallest (residential and small commercial), a requirement that distribution utilities buy from cogenerators embedded within their systems, and a requirement that NSPI buy power from cogenerators under a standard contract to be developed with stakeholder participation. These recommendations give potential developers of cogeneration a wide choice of outlets for any excess electricity they may have.

In addition, the EMGC made several recommendations to remove potential market or regulatory barriers to new cogeneration.

Standard Service

Customers who do not, or cannot, choose an alternative electricity supplier must continue to receive service, which is called standard service. The EMGC recommended that NSPI act as the standard service supplier under its continuing obligation to serve, and that all customers have unbundled transmission and generation charges.

To facilitate competition, the Committee recommended that NSPI offer services necessary for effective competitive supply. These include back-up supply and a system allowing competitive suppliers to buy or sell un-contracted power.

Stranded Costs and Exit Fees

One component of standard service rates is recovery of the fixed costs of facilities needed for the supply. By leaving standard service, customers could shift this cost responsibility to others. The EMGC made several recommendations relating to the calculation of these stranded costs and the conditions for their recovery.

Promoting Energy Efficiency

An important barrier to implementation of energy efficiency is the cost of information on efficient technologies. The EMGC recommended that the government maintain information programs but given the incidence of cost and benefits, they also recommended that the government not place a charge on electricity to fund energy efficiency programs.

Regulator Roles and Market Surveillance

In a restructured market, the regulator often must assume greater and more varied responsibilities. One such new role is often that of a market surveillance function, monitoring the performance of the market and the behavior of the market participants. The EMGC made several recommendations with respect to market monitoring and surveillance and much of the burden would, under these recommendations, fall on the UARB. Following electricity reform in Nova Scotia, the regulator's role will be increased, not decreased. The EMGC expressed its opinion that the UARB's resources should also increase, consistent with that role.

Next Steps

The EMGC concludes its report with a section describing some future processes and procedures that will be needed to implement its recommendations. These include: potential multi-stakeholder processes like the EMGC, investigation of the costs and benefits of a broader market opening, followed by re-consideration of market scope; further detailed design of the mechanisms for the RPS; thepromotion of cogeneration; the creation and filing of the non-discriminatory transmission tariff; development of the market for un-contracted energy;and refinement of market rules needed for the bilateral contract market.

1.0 Introduction

Acting on a key commitment in its *Energy Strategy*,[1] the Government of Nova Scotia quickly established the Electricity Marketplace Governance Committee (EMGC) to advise it on the implementation of electricity-related actions identified in the strategy. The EMGC was planned as a body that would broadly encompass diverse interests. Thus, the government invited the participation of relevant stakeholder groups and urged them to nominate individuals who would represent their respective constituencies as either members or alternates. At the same time the government developed Terms of Reference (Appendix A) for the EMGC, appointed a Chairperson and retained, through its public tendering process, the services of a qualified consulting company to provide the EMGC with independent technical support on the electricity restructuring issues. The EMGC was charged with the responsibility of delivering a final report, containing specific recommendations, to the Minister of Energy.

1.1 ENERGY STRATEGY POLICY OBJECTIVES

Nova Scotia's *Energy Strategy* defined three main goals:

- to create a world-class energy sector that would achieve sustainable economic development in balance with high social and environmental standards;
- to optimize financial, economic, and social benefits in the province's rapidly expanding offshore energy sector; and
- to improve the province's environment and enhance the quality of life for Nova Scotians.

In keeping with those goals, the *Energy Strategy* also outlined the following objectives, specifically relevant to the Nova Scotia electricity sector:

- to maintain access to a secure, reliable and affordable electricity generated in an environmentally responsible manner;
- to encourage long-term competition; and
- to promote the growth of renewable energy sources in Nova Scotia.

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[1] *Seizing the Opportunity: Nova Scotia's Energy Strategy*, December 2001 (www.gov.ns.ca/petro/energystrategy)

1.2 DECISIONS TAKEN BY THE GOVERNMENT OF NOVA SCOTIA

The *Energy Strategy* commits Nova Scotia's electricity industry to carefully increasing competition while simultaneously encouraging the growth of renewable energy sources within its jurisdiction. In order to achieve these outcomes, the strategy commits provincial implementation of the following actions:

- Establish an electricity marketplace governance committee (EMGC), representing a wide range of stakeholder groups, to recommend to the Minister of Energy the implementation, development, structure, and rules for the future electricity sector;
- Give policy direction for the Nova Scotia Utility and Review Board to authorize open access transmission, on NSPI facilities for all generators selling to wholesale customers or export markets;
- Introduce competition within the electricity sector in a staged and measured process beginning with supply to wholesale customers (currently six municipal utilities);
- Introduce competition in future electricity generation and encourage cogeneration;
- Assist the development of an independent power producers' (IPP) renewable sector by permitting access to the NSPI transmission system for green energy customers, and setting, with NSPI, a voluntary target of 2.5 percent (50 MW) of new generation by independent producers;
- Develop information programs to promote the use of renewable energy technologies;
- Take steps to meet US reciprocity requirements to export of electricity; and
- Encourage the use of indigenous coal resources where environmentally appropriate and economically feasible and work to support an appropriate role for coal.

The *Strategy* also recommends two additional goals for the longer term, defined here as post 2005:

- Work with NSPI for the long-term retrofit or replacement of generating systems; and
- Expand green energy programs; establish a long term RPS strategy;
- Continue to improve generation efficiency and reduce overall emissions in the electricity sector.

1.3 EMGC TERMS OF REFERENCE

Terms of reference, developed by Department of Energy officials, consistent with the *Energy Strategy*, resulted in the following responsibilities (the complete terms of reference are included as Appendix A to this report):

Over the Near Term

- Provide recommendations that ensure transmission system access is available to all eligible market participants on an equitable basis.
- Consider the use of exit fees or other methods for handling stranded costs.
- Address responsibility for the non-contestable market (standard offer supply).
- Identify which customers are entitled to standard offer supply.
- Define "renewable" energy for public policy purposes.
- Determine how new capacity is to be added to Nova Scotia's electricity system.
- Design a system for Nova Scotia that retains all benefits they presently enjoy, generally defined as "heritage assets".
- Provide recommendations for the promotion of co-generation.
- Determine how green power marketers should gain access to end-use customers; i.e. physical or financial transactions.
- Define the appropriate role of Nova Scotia Power relative to green power.
- Recommend methods of monitoring green power sellers to ensure that all financial transactions are appropriate.
- Define the target capacity, time frame and market participants appropriate to implement a mandatory Renewable Portfolio Standard.
- Define the circumstances under which net metering would be permitted or encouraged.

Over the Longer Term (post 2005)

- Make recommendations regarding the establishment of workable competition in the Nova Scotia electricity marketplace (i.e., market power issues).
- Make recommendations on market surveillance and enforcement of market rules.
- Recommend mechanisms to permit determination of stranded costs that might result from new investments or competitive supplies.
- Assess Nova Scotia's compatibility with systems in Northeastern North America (including both United States and Canadian jurisdictions)
- Consider issues of reciprocity in relation to transmission developments in both Canada and the United States.

1.4 CONTENTS OF THIS REPORT

Some portions of this document may have appeared earlier in either of two previous InterimReports. Those reports were made available to interested persons either through the interactions of committee members with their constituencies or via access to the EMGC website. Interim Reports were made available as records of work in progress and consequently the contents were subject to possible change from community input or additional committee deliberations. Therefore, only the final report, with its attendant recommendations, is the complete and final record of the EMGC.

2.0 The Electricity Marketplace Governance Committee

2.1 COMMITTEE COMPOSITION

In keeping with a fundamental commitment of the *Energy Strategy*, the government established a small broadly based group of stakeholders. EMGC members (see Appendix B) include one representative from each of the following seven stakeholder groups:

1. Canadian Federation of Independent Business, representing small and medium business;
2. Canadian Manufacturers and Exporters, representing large industrial users;
3. Consumers Association of Canada;
4. Electricity Consumers Alliance of Nova Scotia;
5. Municipal Electrical Utilities of Nova Scotia Cooperative;
6. Nova Scotia Power Inc., a regulated, vertically integrated electricity service provider;
7. Renewable Energy Industries Association of Nova Scotia.

In addition, the government invited representatives from the Nova Scotia Utility and Review Board and the Nova Scotia Chamber of Commerce to participate as official observers.

EMGC members agreed to seek and represent the views and interests of their own organizations along with the broader interests of their respective stakeholder constituencies. In an effort to ensure that the EMGC process was open and fully transparent to the public, the government created a regularly updated web site (www.gov.ns.ca/petro/energystrategy/emgc). All interested parties were invited to follow the committee proceedings by accessing the web site and/or submitting comment to their respective constituency representatives.

2.2 THE EMGC PROCESS

At the committee's inaugural meeting on May 28, 2002, members agreed to abide by the provisions set out in a document entitled *Nova Scotia EMGC Mandate and Rules of Conduct* that provides the committee mandate, along with guidelines for decision-making and internal workings. This document, which lays out specific tasks and responsibilities, supplements the EMGC's Terms of Reference.

The EMGC generally met in full day plenary sessions at two-week intervals. The chair, project manager and consultants acting on direction provided by the membership, set the agenda for each meeting.

In an effort to give EMGC members a good understanding of the important and complex issues under consideration, the committee consultant prepared issue papers and/or electronic presentations on appropriate topics. Following extensive discussion on each issue, a hypothetical "strawman" was prepared for committee consideration. Strawmen are used to present a detailed set of proposed options or alternatives for a specific set of issues, and as such they present a useful starting point for discussion, debate and deliberation by the Committee. The use of strawmen is an iterative process that permits continuous refinement, revision and amendment as the decision process proceeds.

All Committee members were encouraged to submit documents and/or presentation materials to the Committee. Various NSPI staff members made a number of useful presentations and circulated some very informative background documents. In addition, the committee received a presentation by Sir Graham Day, who provided it with some additional contextual insights, based primarily on his experience with electricity restructuring in the United Kingdom and Ontario. Mr. Robert Cary, of Robert Cary and Associates, reviewed the committee's work and provided valuable insights.

2.3 CRITERIA FOR DECISION MAKING

The Committee agreed that its mode of operation would be to seek consensus with respect to all of its decisions. However, if that was ever deemed to be unattainable, the Chair could then establish a Committee position, from which members would have the right to dissent. This latter condition never occurred as consensus was reached on every occasion, and unanimity on all but several.

During the third meeting of the EMGC, Issue Paper No. 1, entitled *Overview of Objectives and Criteria for Decisions,* was tabled, discussed and ultimately adopted, thereby providing the committee with a framework for future decision-making. Accepted criteria for decision-making include:reliability, transparency, fairness, robustness, enforcement ability, environmental impact and protection of existing Nova Scotia consumers.

3.0 External Influences on the Nova Scotia Electricity Market

Discussions within the EMGC regarding the future of the electricity market in Nova Scotia were partially set within the broader context of change currently underway across the full extent of the electricity sector. To properly appreciate the Nova Scotia discussions, it is important to have some understanding of influences presently in play outside the province. These extend across a broad spectrum that includes events at the global, North American, national and regional levels.

3.1 ECONOMICS OF ELECTRICITY RESTRUCTURING

Around the world, the electricity supply industry is undergoing profound change, moving away from its traditional structure of vertically integrated (combining electricity generation, transmission and distribution) monopoly suppliers. Many jurisdictions are actively considering change while others have already implemented restructuring; and some have even reversed these newly implemented reforms, having had unanticipated negative experiences. Most restructuring includes several key elements: greater reliance on market forces to set the price of electricity generation; greater competition to supply end-use customers, and the maintenance of transmission and distribution activities as regulated monopolies. The first countries to pursue this agenda included England, Argentina, Norway, Australia, and New Zealand.

Two important changes have enabled this move away from monopoly: improvements in the efficiency of generation, and the revolution in information technologies. Thirty years ago, progressively larger generation facilities were more cost-efficient than their smaller predecessors. However, large-scale plants also embraced greater risk. More recently, moderate scale gas turbine technologies have become as cost-efficient as much larger plants, thereby diminishing the need for large-scale generation monopolies.

Electricityrestructuring is uniquely challenging because electricity must be generated simultaneously with its use, and usage varies widely over time. Therefore, a centralized body or agency must, for reliability and cost reasons, balance supply with demand by continuously adjusting generation to meet changing load conditions. Managing this task at the least possible expense requires instantaneous access to full system-wide costs and technical information. Before the advent of high-speed information and communication technologies, only single owners had access to the requisite data. Today, with appropriate technologies, an independent dispatching body can gather market data, process it, use it to effect price discovery and then using that information create a dispatch schedule. Thus, with the introduction of competitive generation it follows that the retail supply of electricity can also be competitive.

One additional item worth mentioning is the growing political movement away from price regulation towards more open and competitive markets. Reduction of detailed electricity price regulation is simply following the lead of other industries. Price and service offerings in telecommunications, natural gas, and transportation have all been largely removed from the strict purview of regulators and left to markets to decide. The remaining degree and type of regulation varies across jurisdictions and industries.

In electricity, the transition from fully regulated utility to market competition has necessitated the introduction of sweeping changes in most jurisdictions. These have included: a reassessment of the degree and manner of regulation; movement away from vertical integration toward unbundling (separation of the generation, transmission and distribution functions); greater regional integration governed by a common set of principles, and, in order to stimulate competition, fair and equitable access to transmission capacity. In the United States these principles have been vigorously applied over the past decade through the actions of the Federal Energy Regulatory Commission (FERC) that, because of the interconnectedness of the continental electricity system, is having a growing influence on decision-making in Canada.

Such sweeping changes, however, may come with significant public and political upheaval. The EMGC, drawing on information from other jurisdictions, acknowledged that a broader market opening would bring with it higher transition and operating costs and greater risk of price volatility. In a few jurisdictions governments have reacted to widespread concern over price volatility, the result of which has been to delay or stop restructuring efforts. The Conference Board of Canada, in its May 2003 briefing, "Curbing Enthusiasm for Electricity Reform" observed that:

> *"Across North America, the bloom is off the rose for electricity restructuring... California's (and now Ontario's) well publicized troubles, the Enron collapse, and the financial crisis in the energy industry have slowed progress on electricity restructuring. Some jurisdictions are viewing this loss of momentum as an opportunity to reconsider market design in order to avoid the problems and pains seen elsewhere. Other regions are questioning the fundamental philosophy of liberalization."*

It is within this broad context that the EMGC had to consider the implementation of the *Energy Strategy.*

3.2 THE UNITED STATES FEDERAL ENERGY REGULATORY COMMISSION

In the United States, the Federal Energy Regulatory Commission (FERC) creates and enforces regulations that affect most electricity industry participants. Driven towards greater competition by both economic and political considerations, FERC has been a persistent and effective motivating force behind the restructuring of the wholesale electricity industry in the United States.[2] FERC's broad jurisdiction is in contrast to that of Canada's National Energy Board which to date has only been granted authority over the export of electricity and over the construction and operation of international power lines.

Following the promotion of restructuring in the gas and oil transmission industry, FERC's first major restructuring directives affecting the electricity industry appeared in 1996, as Orders 888 and 889. In Order 888, FERC determined that non-discriminatory open access transmission services, including access to transmission information, and stranded cost recovery were the most critical components of a successful transition to competitive wholesale electricity markets in the United States. In Order 889, issued concurrently with Order 888, FERC also imposed standards of conduct governing communications between a utility's transmission and wholesale power functions, to prevent the utility from giving its power marketing arm preferential access to transmission information. Under that Order utilities owning, controlling or operating transmission facilities were required to create or participate in an Open Access Same-Time Information System (OASIS) so that existing and potential transmission customers could have real-time, non-preferential access to information about available transmission capability, prices and other matters affecting the transmission system.

Order 888 contained a *pro forma* Open Access Transmission Tariff (OATT), the proper use of which would constitute compliance with the FERC directive for non-discriminatory open access transmission services. Together, Orders 888 and 889 required that vertically integrated public utilities were to be functionally unbundled. This meant (1) that such utilities were to take wholesale transmission under the same terms as offered to customers, (2) they were to state separate rates for wholesale generation, transmission, and ancillary services, and (3) they had to rely on the same electronic information system that transmission customers rely on to get information about the transmission system.

To encourage non-discriminatory access to transmission systems, FERC's *pro forma* OATT included a reciprocity provision. It said that all customers (and their affiliates) that own, control or operate interstate transmission facilities and that take service under a public utility's open access transmission tariff must offer comparable (not unduly discriminatory) services in return. While this provision was aimed primarily at US utilities outside of FERC jurisdiction, such as cooperatives, it also affected Canadian utilities. For example, in response to the FERC Orders Quebec restructured Hydro-Quebec into unbundled generation and transmission arms. This allowed them to get a FERC license, which permits Quebec to access the neighbouring transmission network to market electricity in the United States.

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[2] FERC does not have jurisdiction over retail electricity competition; the states do. The degree of retail competition therefore varies widely from state to state.

Response to the FERC Orders by American utilities introduced significant restructuring of electricity generation and an increase in wholesale competition. In many states, especially those that adopted retail competition, vertically integrated utilities were forced or encouraged to sell off their generation assets. Several regions created competitive wholesale pool markets. However, many generators continued to complain that transmission owners discriminated against them. Also, differences between markets led to difficulties when trading electricity across borders.

FERC responded to these difficulties by issuing Order 2000, the intent of which was to put all transmission owners in the US under the control of regional transmission organizations (RTOS). FERC concluded that the establishment of independent RTOs would eliminate undue discrimination in transmission, enhance the benefits of competitive electricity markets and could improve efficiency in transmission grid management and reliability. Each RTO would encompass a single transmission market, allowing generators to move electricity over long distances without incurring additional transmission charges, and each RTO would be responsible for dispatch within its area. In later rulings, FERC made it very plain that it envisioned only four or five very large RTOs, extending across the United States.

Full access to transmission within an RTO is provided with full membership. However, that membership also carries the reciprocal responsibility to accept control by the RTO, which for Canadian jurisdictions implies a potential loss of sovereignty. Only one Canadian utility has joined an RTO to date, while others created parallel but coordinated systems that readily trade with a neighbouring RTO. The FERC reciprocity requirement remains in effect, so that Canadian utilities that desire access to US transmission systems must offer reciprocal access to their systems.

Dissatisfied with the pace of RTO formation, and still insisting that trading should encompass broad geographical areas, FERC issued a Notice of Proposed Rulemaking (NOPR) in July 2002, for a Standard Market Design (SMD). The SMD would have imposed a market design with a competitive pool and locational marginal pricing in all of the RTOs. In the face of substantial resistance to its Standard Market Design NOPR, FERC has recently (April 2003) issued a White Paper describing its current position. In that paper, it has retreated from the requirement that all transmission owners: join an RTO, participate in mandatory competitive wholesale pools, and engage in locational marginal pricing within the Standard Market Design.

FERC, as an instrument of policy, speaks for the U.S. federal government. A direct FERC equivalent does not exist in Canada. The National Energy Board (NEB), although a significant presence in both the continental natural gas sector and the international electricity trade, is a very much smaller presence in domestic electricity policy. Since discussion and mediation are not normally conducted between FERC and NEB the responsibility naturally devolves to individual provinces. For the larger provinces this may be less of a disadvantage but in the Maritimes, where the aggregate population is less than that of Greater Boston, it is daunting, especially since individual provinces seldom coordinate their activities, generally preferring to "go it alone".

3.3 NEW BRUNSWICK AND ELECTRICITY RESTRUCTURING

The New Brunswick electricity industry is dominated by a vertically integrated, government-owned monopoly, New Brunswick Power. NB Power uses a mix of generation technologies and fuels, but it relies heavily on its Point Lepreau nuclear unit along with several large fossil-fired units.

New Brunswick reacted to changes in the electricity market with a public consultation process designed to facilitate the consideration of future electricity options. This process resulted in the release of a *White Paper* in 2001.[3] In it, the government committed to creating a limited competitive electricity market by April 1, 2003. The proposed market design would allow both wholesale customers (i.e., municipal utilities) and large retail customers directly connected to the transmission system (i.e., those with connection capacity of 750 kW or more) to choose competitive suppliers. Combined, these user categories make up approximately 30% of total demand. To allow competition, competitive generators would get non-discriminatory access to the transmission system.

New Brunswick Power relies on power exports to New England for a significant fraction of its revenue. Profits on these exports have kept New Brunswick's domestic electricity prices lower in some years by as much as 15%. Therefore, a driving force behind the *White Paper* commitment to open access transmission was the need to preserve and enhance access to New England markets for New Brunswick power.

To further this end, the Government of New Brunswick appointed a Market Design Committee, a multi-stakeholder group, to recommend on the implementation of electricity sector policies outlined in the *White Paper*. In keeping with these recommendations and with prior commitments, New Brunswick Power filed a FERC-compliant OATT. After hearings before the New Brunswick regulator, the Board of Commissioners of Public Utilities, the New Brunswick Power tariff (OATT) was approved. The OATT contains reciprocity provisions that permit the New Brunswick system operator to deny NSPI and its affiliates access to the New Brunswick transmission system if NSPI does not have a comparable open system. The ruling of the NB Board of Commissioners of Public Utilities granted NSPI and its affiliates a temporary waiver on the conditions that NSPI and its affiliates adopt standards of conduct compatible with FERC Order 889 and implement a reciprocal transmission sys-

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[3] Government of New Brunswick, Ministry of Natural Resources and Energy, *White Paper: NewBrunswick Energy Policy*, January 2001. (www.gnb.ca/0085/toc.htm)

tem. The waiver expires in January of 2005. This provision in the New Brunswick OATT is but one example of a constraint exercised on Nova Scotia by the fact that its only existing access to electricity markets outside Nova Scotia is through the "inter-tie" connection between the two provinces. The New Brunswick Power OATT was expected to be implemented commencing April 2003, but its implementation has been held off until at least 30 September 2003.

3.4 NOVA SCOTIA AND THE ENERGY STRATEGY

In 2001 Nova Scotia embarked on a consultative process to examine provincial energy policy, which resulted in the release of an *Energy Strategy*.[4] Given Nova Scotia's significant coal and gas resources, the strategy had relatively greater emphasis on development of energy supply than did New Brunswick. It also gave considerable attention to the structure of the electricity supply industry. Nova Scotia Power Inc. (NSPI), a vertically integrated, investor-owned monopoly utility, characterizes that industry.

The Nova Scotia electricity industry has not been as export-oriented as that in New Brunswick, due in part to the difficulties inherent in accessing the American markets. However, Nova Scotia does have important transmission links with New Brunswick, which both Nova Scotia Power and New Brunswick Power have used to share reserves to the advantage of their respective customers. Reserve sharing with New Brunswick has obviated the need to build as much reserve capacity as either province would otherwise have needed to maintain their high levels of reliability. Also, the link with New Brunswick permits the export of power to Prince Edward Island.

The Nova Scotia *Energy Strategy* explicitly declares the Provincial intention to approach electricity competition gradually and carefully. The first step would open only the wholesale market (i.e., municipal distribution utilities) to full competition, which represents less than 2% of total electricity demand in the province. This degree of market opening is similar to that created in Quebec, where it was deemed sufficiently reciprocal for FERC to grant Hydro-Quebec transmission access in the United States. Beyond the wholesale market, the *Energy Strategy* also stipulated that producers of electricity from renewable energy sources would be able to sell to all electricity consumers, while later in this report the EMGC recommends that cogenerators be given broader market access under certain conditions. The *Energy Strategy* suggested that the initial gradual opening, recommended in that document, would be accompanied by NSPI continuing to have an obligation to serve electricity consumers in the province.

For Nova Scotia electricity producers to export power to consumers outside Nova Scotia, they must be able to access transmission into and (for sales to the United States) out

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[4] Government of Nova Scotia, Seizing the Opportunity: An Energy Strategy for Nova Scotia, 2001

of New Brunswick. A major issue in the restructuring of the Nova Scotia electricity market, therefore, is whether the changes made in Nova Scotia will give producers and consumers in this province the right to non-discriminatory transmission access in New Brunswick and beyond. To achieve that end, the reciprocity provisions of the New Brunswick OATT plus their counterparts in the United States are clear that Nova Scotia must give equivalent transmission access. This illustrates the cross-border reach of FERC.

3.5 SIZE OF THE NOVA SCOTIA MARKET AND ECONOMIES OF INTEGRATION

The size of the Nova Scotia electricity system has had a direct influence on the character of the EMGC deliberations. In particular, the EMGC did not consider the issue of possible disintegration or divestiture of the present integrated electricity utility. Other jurisdictions have legally separated generation, transmission, and distribution functions from previously vertically integrated utilities. Also, it is not uncommon in restructuring to mandate the divestiture of generation assets into competitive units under separate ownership.

The *Energy Strategy* states that NSPI will remain a vertically integrated utility and retain the obligation to serve. There is a perceived value to Nova Scotians in the present and near-future cost of NSPI's generation. Electricity prices in Nova Scotia are high in Canadian terms, but quite attractive compared to the adjacent northeastern North American Market, to which we are connected through New Brunswick. There is also a danger that New England prices will "back up" into Nova Scotia in an unconstrained market, as supply will go to where it is rewarded by price. The EMGC has given attention to preserving the benefits of heritage assets on the theory that native customers have paid for existing generation capacity and transmission infrastructure and are therefore entitled to any benefit they can provide.

The EMGC was prepared to go beyond the *Energy Strategy* in some areas, if it felt that a more aggressive approach was warranted. However, the Committee learned that the size of the Nova Scotia market was such that any divestiture by NSPI could bring increased costs, rather than increased benefits. The EMGC was also advised that, based on economic theory, a truly competitive market would only be possible if it contained a minimum of five or six generation companies of roughly equal size, with none having more than 35% of market share. Navigant Consulting suggested that the entire load of approximately 2000 MW in Nova Scotia is not large enough to create an economic generation company, said to be something on the order of 3500 to 8500 MW. Separating NSPI's generating plants would result in relatively small business units. NSPI presently has about 2200 MW of generation made up of four coal/petcoke fired thermal plants, one heavy oil/natural gas thermal plant, one natural gas combustion turbine, several oil-fired combustion turbines, one tidal plant, several hydro stations, and 1.2 MW of wind generated electricity. With this mix it would not be possible to create a sufficient number of separate companies of adequate size to compete efficiently. Integrating Nova Scotia into a larger market might be a more likely possibility, if Nova Scotia was not a small peninsula at the northeastern extremity of North America, with limited interconnection to the rest of the continent. Such an approach, were it to come to pass, would be described as the Regional Transmission Organization model. It might possibly be desirable for Nova Scotia, if the value is high enough to exceed costs.

For these reasons, the Committee sought to introduce competition *within* Nova Scotia, initially without the attendant risks associated with the break-up of NSPI. The EMGC recognized, however, that only limited competition can be created in this manner, and individuals expecting a bonanza of lower prices from increased competition will feel betrayed. However, the EMGC was charged to recommend a "cautious and measured approach" in its efforts to introduce greater competition. Further to that goal the committee recommends additional study of the potential for even wider market scope. This would include consideration of cost/benefit analyses, divestiture, market power, and balance of competition.

3.6 ENVIRONMENTAL REGULATION

Growth in public concern about environmental issues has measurably impacted the electricity generation sector, with more stringent environmental regulation in jurisdictions with significant amounts of coal-fired generation. Many of those jurisdictions already have regulations in place governing SO_2 and NO_x air emissions. Both SO_2 and NO_x cause acidrain, while NO_x is a precursor of smog. Standards for both of these pollutants are becoming increasingly stringent, but the mode of regulationis slowly undergoing alteration toward greater market orientation. Ontario, for example, is enacting an emissions cap and trading system covering SO_2 and NO_x. The caps should reduce emissions from the electricity generation sector by half before 2010. Under the trading system, rather than forcing all generators to reduce to the same standard, reductions can come from generators with the least-cost opportunities to reduce emissions. Limits on SO_2 and NO_x emissions in the United States could impact the ability of Canadian generators to sell power to that market.

The *Energy Strategy* calls for NSPI to reduce SO_2 by 25% from current levels by 2005 and for NSPI and other industrial participants to further reduce SO_2 to achieve a cumulative reduction of 50% by 2010. For NSPI this means reducing yearly emissions from 145,000 tonnes to 108,750 tonnes by 2005 and 72,500 tonnes by 2010. NSPI's NO_x emissions are to be reduced by 20% below 2000 levels by 2009. This means a reduction from 26,700 tonnes in 2000 to 21,400 tonnes by 2009. NSPI's mercury emissions are also to be reduced by 30%

below 1995 levels by 2005; in 2005 further reductions to between 60 and 90% will be set by the Canadian Council of Ministers of Environment. By 2005 NSPI's emissions will be controlled to about 135 kg per annum. This target level is only approximate as the base year 1995 emission level has yet to be agreed upon.

The environmental consideration with potentially the largest impact is that of greenhouse gases (GHGS). Canada has signed the Kyoto Accord to the International Protocol on Climate Change, which will commit it to reducing its GHG emissions to 6% below their 1990 levels by 2008-2012. In Nova Scotia, electricity generation accounts for approximately 44% of GHG emissions, mostly from coal fired stations. Implementation of the Kyoto Accord could adversely impact the electricity sector. Consequently, details of the Kyoto implementation, along with the reductions required from each province, are still under multi-lateral discussion in Canada.

4.0 Market Scope and Market Model

4.1 EMGC DISCUSSIONS AND RECOMMENDATIONS ON MARKET SCOPE

The EMGC clearly understood the tradeoffs that were required when it made a decision on market scope. The primary motivation for change was the desire to obtain the benefits of competition for electricity consumers in Nova Scotia, while remaining consistent with trends underway in North America and the world. This approach is premised on the belief that Nova Scotians must learn to accept the change that surrounds them and to adjust to it in ways that reflect their native values. A moderating influence was concern for the costs of restructuring, uncertainty as to the benefits that might accrue in the small Nova Scotia market, and the clearly expressed intent of the *Energy Strategy* for a gradual transition to electricity competition in Nova Scotia.

The EMGC agrees with external advice that posits several major benefits from further integration of electricity interests among the three Maritime Provinces, and eventually with adjoining jurisdictions. Integration could provide economies of scale, greater operating efficiencies, a larger market offering consumers greater choice, and reduced vulnerability to external forces presently being felt in this region. The degree and nature of further integration involves political and policy questions. The EMGC is aware of this direction, and has tested its decisions against the question as to whether they are compatible with the likely future direction of this market.

Having reviewed the available market models, and gained some understanding of their advantages and disadvantages, the EMGC considered the subject of market scope. It was felt that these two should be considered in tandem since the committee's decision on the latter could strongly influence costs through the resultant choice of a market model.

4.1.1 MARKET SCOPE IN THE ENERGY STRATEGY

A key objective in the electricity section of Nova Scotia's *Energy Strategy* is to phase in competition in the Nova Scotia electrical industry[5] As a first step, the *Energy Strategy* indicated that competitive suppliers would gain access to the wholesale market and both cogenerators and independent generators would be allowed non-discriminatory access to the transmission system in order to supply eligible customers and export markets. The *Energy*

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[5] Energy Strategy, Volume 2, Part III, Electricity, pg. 4.

Strategy also noted that it is important to create an open-access transmission system when considering export sales to the United States.[6]

Opening the wholesale market to competition will expose only a very small portion of the total market to competitive supply. Wholesale customers comprise six municipal utilities, which collectively account for about 1.6% (less than 50 megawatts) of peak demand in Nova Scotia. As the *Energy Strategy* observed, this constraint would mean that NSPI could lose only a small fraction of its total market.

The *Energy Strategy* also committed to using expanded consumer choice as a way to promote certain more desirable forms of generation. One commitment was specifically directed to independent power producers (IPPs) who sell electricity produced from renewable energy sources. They are granted direct access to retail customers. This is clearly a cautious approach to market scope.

The *Energy Strategy*'s commitment of transmission access for cogenerators does not provide any more favourable treatment than other generators. However, given the *Energy Strategy* support for cogeneration, the EMGC did consider additional means, including broader market access, to promote cogeneration. EMGC recommendations on this subject are in Section Eight.

In Nova Scotia, exposure to electricity market forces is expected to increase regardless of further expansion of the market to retail customers. The *Energy Strategy* states that when the system requires new supply it will be obtained through a competitive process. The UARB will initiate and oversee a Request for Proposals (RFP) process, followed by competitive selection of an investment project(s). The cost of the successful project will depend on market conditions at the time of the RFP. That cost will be included in the rate base, but the process will introduce a greater degree of market responsiveness to electricity costs in Nova Scotia.

4.1.2 MARKET SCOPE IN OTHER JURISDICTIONS

Many jurisdictions that have restructured their electricity industries have chosen a gradual approach to broadening market scope. Typically, they first allow only the largest customers to choose competitive supply. Over time, the scope of the market can be expanded until all customers, even the smallest retail customers, can choose among competitive suppliers.

This gradual approach allows both the market design and market model to be tested and improved before exposing all customers to the vagaries of competition. In general, higher price volatility accompanies increasingly competitive markets. Keeping the market small initially can reduce the impact of price volatility on residential and other small customers. Also, a narrower market scope is likely to incur lower transition and administrative costs than a broader one. The flip side, of course, is that the more competitive the market opening is, the greater the pressure it puts on producers to increase efficiency and keep costs down.

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[6] Ibid, pg.18

Other jurisdictions in Canada have chosen different approaches. In Ontario, the entire market was initially opened at a single stroke, though subsequent policy changes have limited retail competition. In Alberta the initial opening embraced only large customers, including the large municipal utilities. Quebec, on the other hand, has opened its market only to a relatively small group of municipal utilities.

New Brunswick, as the final example, is currently taking steps to allow municipal utilities and large industrial customers, approximately 30% of the total market, to choose competitive supply. To implement these changes it is creating an Independent System Operator (ISO) for its bilateral contract market, an OATT and an OASIS (Open Access Same-Time Information System). This transition in market design will incur significant costs, which must also include those associated with the corporate unbundling of New Brunswick Power.

4.1.3 EMGC DISCUSSIONS ON MARKET SCOPE

During its discussion, the EMGC, drawing on information from other jurisdictions, acknowledged that a broader market opening would bring with it higher transition and operating costs and greater risk of price volatility. The advantages that might accrue from competitive entry into the Nova Scotia electricity market must be considered relative to the costs and risks associated with a wider market opening.

To understand better the potential tradeoffs described above, the EMGC reviewed several different permutations in the Nova Scotia electricity market. EMGC members expressed a need for more information on several issues relating to the potential impact of a broader market scope. These include: some assessment of the potential complexity of the restructuring process; some estimates of additional associated costs; and some estimate of price volatility for those participating in the market. The Committee also wanted additional information regarding gains that might reasonably accrue from greater competition and how those gains might be distributed among potential beneficiaries.

One potential benefit of increased competition is the expectation of a reduction in generating costs. However, competitive markets, in the presence of market power, cannot ensure that cost reductions will be passed on to consumers. Any electricity producer with market power can maintain higher prices, despite lower costs, and thereby increase profits.

Navigant Consulting made a preliminary estimate of between $4 million and $9 million for the cost of designing and implementing an OASIS and OATT, and functionally unbundling the NSPI transmission system. The actual amount will depend on the regulatory review, the extent of functional unbundling, and the actual cost of developing the OASIS. Incremental ongoing administration costs are additionally estimated to range from $1.5 to $2.0 million annually. NSPI provided an alternative estimate for the cost of an open access transmission tariff to be about $1.8 million. Both estimates are acknowledged to be first approximations. Also, they do not include costs for the development and operation of additional structures that might be needed for a more competitive market. Actual costs will fall under the purview of the UARB.

4.1.4 EMGC RECOMMENDATIONS ON MARKET SCOPE

To aid the decision-making process, the EMGC considered two competing models. The first limited the market to the municipal utilities, while the alternate model would allow large industrial customers freedom to choose competitive sources of supply. Information provided by NSPI showed that the 14 largest industrial customers in the province, all of which are directly connected to the transmission system, represent approximately 24% of total electricity demand. In this model, the large industrial and municipal utilities together would make almost 26% of the total market eligible to purchase competitive electricity supply.

Within the scope of these two models, Committee attention then focused on the extent of market change that would be required to implement each level of competition.

Three alternatives emerged:

- Competition would be limited to the municipal utilities and a transmission tariff would be developed but it could fall short of a full OATT, for example, it would not necessarily have an OASIS;
- Competition would be limited to the municipal utilities and a FERC-compatible OATT would be developed;
- Competition would be extended beyond wholesale customers to include large industrial customers, a FERC-compatible OATT would be developed and additional institutions (e.g., system operator) would also be created or restructured as necessary.

The Committee expressed a clear preference for the first option. Following that preference it was able to formulate and adopt recommendations on market scope. Thus, the first recommendation limits the initial market opening to the municipal utilities, as indicated in the *Energy Strategy* and for the sake of clarity included a reference to the decision regarding broader access for sellers of electricity from preferred sources.

The scope of an electricity market is defined by how much of it is open to competition. In a fully competitive retail market, all end use electricity customers are free to choose to buy electricity from any supplier.[7] Other levels of competitive opening are possible, and in many markets the choice has been to open the market in phases. Under such a structure, choice is typically made available first to the largest customers, then to gradually smaller customers until all are able to choose competitive supply. For the EMGC, the discussion of market scope was a discussion of what customers it should recommend as eligible to choose competitive supply of their electricity energy at what point in the Nova Scotia market development.

Recommendation 1

The EMGC recommends that Nova Scotia's initial market opening, to encourage electricity competition, be restricted to wholesale customers, who will then be eligible to purchase electricity from any competitive supplier; and that sellers of electricity from cogeneration, or from renewable resources located in Nova Scotia, be able to sell directly to consumers under certain conditions.

In the discussion leading to this recommendation, the Committee recognized that such a limited market opening is unlikely to attract sufficient competitive entry to have a significant impact on electricity generation costs. The EMGC recognized, however, the potential for a broader market opening to bring greater risks, including more price volatility.

One possibility considered on market scope was that the EMGC would recommend a future date for a wider market opening. However, the committee eventually concluded that additional carefully compiled information on the costs and benefits of such an opening would be required before a reasonably informed decision to recommend it would be possible.

Recommendation 2

The EMGC recommends that the Government of Nova Scotia begin a detailed quantitative analysis of the costs and benefits associated with broader electricity competition in the Province. Such an analysis is necessary for any further stakeholder and/or government consideration to broadening electricity competition.

The EMGC does not expect this analysis to be undertaken until after the completion of its Final Report, so no recommendation will be forthcoming based on that additional work. However, the EMGC is clear in its view that such an analysis should be the basis for any further deliberations on the subject of further market openings.

Recommendation 3

The EMGC recommends that the Government of Nova Scotia resume deliberations regarding the possibility of broader electricity competition when the cost and benefit analysis has been completed.

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[7] That part of the supply that consumers can choose is the commodity portion of electrical energy. The delivery functions – transmission and distribution – remain regulated monopolies.

The EMGC wishes to record its opinion, reached after consideration of relative customer sizes, that any future review of a further market opening should consider allowing large industrial customers, directly connected to the transmission system, to choose from competitive electricity suppliers.

4.2 MARKET MODELS

A market model defines how an electricity system will carry out the basic activities of deter mining the quantity of electricity generated, at what price, and with what resources. Market models reviewed by the EMGC include a fully competitive pool, a single buyer model, and a bilateral contract market. Some market models are independent of market scope so that there is not necessarily a direct link between the two. Although, in general, the broader the scope, the more competitive the model, so that any discussion of a future model naturally tracks that of market scope.

The Committee discussed several electricity market models. The existing Nova Scotia model is that of a vertically integrated monopoly utility, Nova Scotia Power, Inc, a private corporation and subsidiary of Emera Inc. NSPI will continue to be a monopoly end-use supplier if the market does not embrace more than wholesale customers. However, its transmission operations need to be functionally separated if the transmission system is to meet independence criteria laid out in FERC Order 888.

Other models discussed by the EMGC include:

- A market based on bilateral contracts between generators and wholesale and large industrial retail electricity buyers;
- A spot market organized around a bid-based pool administered by an independent system operator (ISO); and
- A single buyer/reseller market.

4.2.1 BILATERAL CONTRACT MARKET

Bilateral contracts are agreements between electricity generators and bulk electricity customers (typically, wholesale or large retail) for the delivery of electricity. They can be financial or physical bilateral contracts. A financial contract specifies the amounts, time of delivery, price or price formula for the settlement. Actual generation and delivery take place according to market practice, so that contract participants settle between them any differences between their contract price and the price in the market.

A physical bilateral contract is scheduled with a system operator and specifies amounts of injections and withdrawals, the timing of these events, and the points on the system where they are to take place. In order to be an effective contract, a physical bilateral should also include transmission rights between the injection and withdrawal points.

The bilateral contract model can operate essentially as a form of fringe competition to a dominant generator. Over time, bilateral contracts could increase their fraction of the total market, as customers better understand the market or as more of them become eligible to choose competitive supply. A bilateral contract market used in this way can lead to the gradual implementation of competition into electricity supply.

A bilateral contract market does require several other conditions. Most important is the need for open and non-discriminatory access to the transmission system for all potential buyers and sellers. To fulfill the bilateral contracts, the seller must be able to inject electricity into the system, and the buyer must be able to withdraw it. If the transaction is subject to arbitrary pricing or scheduling by a system operator who functions essentially as a competitor, then the market is not likely to be competitive. Additional conditions include a sufficient number of potential customers and a market price sufficiently high to attract new entrants.

For a small market, such as Nova Scotia, a major advantage of a bilateral market is that it is likely to have lower transition and administrative costs since it may not require the creation of a new market operator. In addition, it promotes a wide range of contractual arrangements and terms.

Other advantages include:

- Bilateral contract markets have lower price volatility than competitive pool markets, since prices for most traded electricity are based on contract terms; and
- In general, bilateral contract markets are less susceptible to the exercise of market power than either of the other models considered.

The major disadvantage of a bilateral contract market is that it does not create strong incentives to move market prices towards short-term marginal cost. Prices are set by the contract terms. Also, market participants may have higher transaction costs. Each transaction requires a separate negotiation and the completion of a contract.

Additional disadvantages include:

- The price-setting process is less transparent than it is in competitive wholesale pool markets;
- The market operator may not be independent of other market participants, creating the possibility of actual or apparent bias; and

- A dominant supplier in a bilateral contract market could use its supply position and its customer relations to deter entry by contracting to meet all actual and expected demand.

4.2.2 COMPETITIVE WHOLESALE MARKET

This model entails the creation of a region-wide competitive wholesale spot market in which an Independent System Operator (ISO) or RTO administers a regional dispatch based on offers and bids submitted by market participants. Much of the actual electricity trade may still be by bilateral contract, but the competitive spot market provides real-time price transparency for all participants. This is the market form adopted by many jurisdictions that have restructured. A real-time market is mandated in the Standard Market Design (SMD) of the FERC Notice of Proposed Rulemaking (NOPR) of July 2002 and in its recently released Wholesale Power Market Platform *White Paper*.[8] The wholesale pool market has many sellers and many buyers who compete with each other. Some buyers may be distribution companies who buy electricity from the pool and resell it by passing the wholesale price through to their end-use customers. Other wholesale buyers can include other resellers and large electricity users.

Prices in the wholesale pool are based on competitive offers and bids submitted by buyers and sellers. The system operator uses the offers and bids to find the price that exactly clears the market. The market-clearing price is that price at which the offer price for the last increment of electricity sold is equal to the bid price for the last increment of electricity bought. The system operator then dispatches the system by scheduling all generation offered at less than the market clearing price and all demand bidding at more than the market clearing price. All electricity traded in the pool is priced at the market-clearing price.

Competitive wholesale pool markets have several advantages. The most important of these is that, in the absence of market power, they have a strong tendency to drive prices towards incremental generation cost. Such prices send a strong signal to purchasers from the pool as to the costs of their usage of electricity, and lead to economic efficiency. However, the presence and exercise of market power can prevent consumers from enjoying the benefits of economic efficiency.

Other advantages of competitive wholesale pool markets are:

- They provide transparency in both price and price setting;
- The spot market can be highly liquid;

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[8] FERC, *White Paper: Wholesale Power Market Platform*, April 28, 2003

- They provide a basis for trading other energy contracts, such as contracts for differences or energy derivatives; and
- Costs of market transactions are low.

Competitive wholesale pool markets also have several disadvantages. Perhaps the most important are the set-up and ongoing administration costs.

Other disadvantages include:

- Greater price volatility. Matching prices to marginal costs, which change hourly, inevitably creates price volatility. But periods of shortage or crises can create much greater volatility and price spikes.
- Competitive wholesale pool markets are susceptible to the exercise of generator market power.
- Market price signals may not provide enough incentives for new generation investment.
- Incentives for new investment in transmission may not be clear. The benefits of new transmission go to customers and generators who gain access to more favorable markets, but there are no easy mechanisms for those who receive the benefit to pay for the investment.
- Competitive wholesale pool markets can be complex and require extensive training and experience for market participants.

4.2.3 A SINGLE BUYER MARKET

The Single Buyer Model for electricity restructuring is centred on the principle of monopsony, a monopoly buyer facing competitive suppliers. It is a first step towards competition from a vertically integrated monopoly utility structure. This model can be implemented in a number of ways. The generation assets of the formerly vertically integrated utility can be sold to several investors, and long-term power purchase agreements (PPAS) established between the monopoly buyer and the new generation companies. Alternatively, the vertically integrated utility can be maintained and it can acquire power through a competitive bidding process or other market-based processes.

The single buyer model might be appropriate for Nova Scotia when less than 2% of the market is open to competition. With its dominance, NSPI will have better ability to manage the market centrally than would any of the individual utilities.

4.2.4 EMGC RECOMMENDATION ON A MARKET MODEL

The decision as to the appropriate electricity market model for Nova Scotia depended on the Committee's recommendation on market scope. The model recommended would need to be compatible with the planned extent of the market opening.

The EMGC reviewed the market models identified above. It was sensitive to their advantages and disadvantages, but also to the concern that it did not wish to adopt a reform that might have to be reversed if the market were to move towards greater competition in the future.

Nova Scotia's present market is a vertically integrated monopoly. The *Energy Strategy* envisioned a model close to a single buyer model, under which competition for new supply will occur through a bidding process with the new supply sold to NSPI to meet its obligation to serve. However, a pure single buyer model does not allow for any contracting between market participants. In Nova Scotia, some participants will be able to offer and accept competitive supply. To do that requires a market mechanism.

The bilateral contract market model is often applied in markets with competition, but no competitive pool. In the United States, for example, most markets under FERC orders 888 and 889 were bilateral contract markets. Given the level of competitive opening of the Nova Scotia market, the EMGC felt that the bilateral contract market was the most appropriate model.

Recommendation 4

The EMGC recommends that eligible Nova Scotia buyers should arrange for competitive supply through bilateral contracts with eligible sellers.

This recommendation mentions eligible buyers and eligible sellers. The eligible buyers are, as mentioned earlier, wholesale customers in Nova Scotia (i.e., the municipal utilities). Eligible sellers could include various kinds of market participants, such as agents, brokers, marketers, and others. These market participants can facilitate transactions because they bring expertise that individual buyers and sellers may not have. They can also aggregate many small transactions into one large economic one. The EMGC therefore recommends that the Nova Scotia market be open to all such participants.

Recommendation 5

The EMGC recommends that eligible sellers in the Nova Scotia competitive electricity supply market include generators, cogenerators, importers, and agents, brokers, traders, marketers and aggregators.

5.0 Planning for Reliability

5.1 ENERGY STRATEGY ASSIGNMENT OF RESPONSIBILITY

The *Energy Strategy* stated that, under its obligation to serve customers in Nova Scotia, NSPI has the "sole responsibility for maintaining adequate supplies of electricity in the province."[9]

The *Energy Strategy* proposes to change this situation marginally. First, it restates NSPI's continuing obligation to serve, which means that it must be prepared to supply electricity to any customer requesting service in Nova Scotia. To do that, NSPI must ensure that it has adequate supplies available, including sufficient reserves to deal with planned and unplanned outages plus expected load growth. This responsibility is unchanged from the present situation.

Second, the *Energy Strategy* prescribes change by altering responsibility for the determination of the need for new generation capacity and for changing the assumption that NSPI will build and own that capacity itself. The *Energy Strategy* assigns two responsibilities to the UARB: to determine when new generation supply is needed, and then to issue (and presumably evaluate) a Request for Proposals to qualified bidders, including NSPI, who would be able to create that supply. If NSPI is successful then the costs associated with new generation would go into its rate base. If NSPI is unsuccessful then the successful bidder would sign a power purchase agreement (PPA) with NSPI, the annual cost of which would would go into NSPI's annual revenue requirement. In a sense, the first responsibility is not new, because the UARB is presently responsible for ruling on requests by NSPI to create new supply. The second responsibility, provision for an RFP, is new, since NSPI, at present, simply builds and owns most of its new capacity. Therefore, the *Energy Strategy* defines the two entities involved in the process as NSPI and the UARB, but does not offer any guidance as to the method of best acquiring public input into the planning decisions.

The EMGC undertook to clarify this process through its recommendations. Clarification could include: the timing of the process to assess the need for new supply; comparison of possible alternatives; a possible process to obtain public input; and some definition of participant's specific responsibilities. The EMGC's recommendations fall into two categories: planning; and process for acquisition of new supply.

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[9] Energy Strategy, Part III, Electricity, pg. 15.

5.2 EMGC RECOMMENDATIONS ON PLANNING

The EMGC agreed that there should be a well defined planning process and that it should have public participation. Conversely, the Committee did not wish to suggest excessive procedural burden on any of the participants. The Committee noted the considerable procedural latitude already available to the UARB when dealing with applications before it. It can choose to have technical conferences or use alternative dispute resolution mechanisms, it can choose to hold written or oral hearings or none at all, and it can specify the issues to be addressed in any hearing. The EMGC felt that this degree of latitude is sufficient to obviate the need for additional procedural overlay.

After considering other alternatives, such as the establishment of a special purpose agency or the transfer of responsibility to government, the EMGC concluded that NSPI is best situated to be the planning agency for the Nova Scotia electricity system. NSPI already has full responsibility for system planning, including that of new supply. The system operator, eventually to be a part of a functionally unbundled NSPI, will have the requisite technical expertise to understand sufficiently the complexities of the system so as to decide issues, such as the best location for new supply. In order for NSPI to meet its obligation to serve customers in Nova Scotia, the utility must be confident that it has adequate supply capacity for the immediate and long term. Given the lead times required to install new generation or transmission capacity, getting such assurance means planning well in advance.

The EMGC wanted to ensure that the planning process allowed for full public input, but without making it an onerous or burdensome process. The following recommendations establish NSPI as the party responsible for producing annual plans, and ensuring that they are filed with the UARB. The act of filing would trigger a period for public comment. The EMGC expects that the UARB would record and place received comments into the public record, and that they would be taken into account when considering proposals for additional resources.

Recommendation 6

The EMGC recommends that, as long as it has an obligation to serve, NSPI be responsible for planning for electricity supply for Nova Scotia.

Recommendation 7

The EMGC recommends that NSPI produce an annual long-range plan, with a horizon of at least 10 years. The plan should address both 18-month and 10-year horizons for the purpose of assessing system capacity and adequacy and for planning to maintain system adequacy

Recommendation 8

The EMGC recommends that NSPI's annual plans be filed with the UARB, and that the UARB open a period for public comment on the plans.

It should be pointed out that the recommendations do not require the UARB to hold hearings or to approve the annual plans. An annual approval process would impose additional costs on both the UARB and NSPI, as well as the preparation and participation costs to interveners.

Recognizing that both demand- and supply-side measures are important in planning for electricity supply systems, the EMGC made an explicit recommendation regarding the content of the annual plans.

Recommendation 9

The EMGC recommends that NSPI's annual plans include consideration of demand-side and supply-side measures to meet any projected need.

5.3 EMGC RECOMMENDATIONS ON THE PROCESS FOR CAPACITY ACQUISITION

The EMGC assumes that NSPI's acceptance of planning responsibility for new supply will result in their identifying a need for action in their annual plans. This would then alert the UARB to an industry perception of need, and allow it to make its own determination. Presuming that both NSPI and the UARB are in agreement, then the latter would initiate a solicitation process for new supply.

As with the planning process, the EMGC was reluctant to prescribe steps that had the potential to become unduly bureaucratic or in any way onerous. The committee recognized that the UARB could use its existing discretion to develop a suitable process. Present UARB practice is to invite public input in both informal and formal processes, as it is doing now with the Generic Rate Design Case and has initiated with its technical conferences on depreciation.

While avoiding the temptation to be too prescriptive with its recommendations, the EMGC does clearly affirm that the processes to be used by the UARB to determine the need for new generation resources or demand side measures should remain open to public participation. Additionally, the EMGC did identify a UARB need to establish timelines for its process.

The following recommendations deal with the process for acquisition of new resources of generation or demand side management.

Recommendation 10

The EMGC recommends that the UARB oversee any competitive process for NSPI to acquire new resources of demand management or generation facilities.

Recommendation 11

The EMGC recommends that there be timelines established for the UARB in its oversight of the process and its approval for the acquisition of new resources.

Recommendation 12

The EMGC recommends that there be an open solicitation process to acquire or contract for new generation or DSM.

Market participants, including NSPI, would submit bids in response to the RFP based on energy and/or capacity requirements identified by NSPI in its filed plan. Following a decision by the UARB, the successful bidder would enter into a formal relationship with NSPI through a power purchase agreement, or in the case of DSM an appropriate contractual agreement.

NSPI could propose to the UARB, as an alternative to including the capital cost of the generating facility in its rate base, a bid to provide the energy at its bid price on the terms and conditions of the RFP and the PPA. Any such arrangement wouldneed to be approved by the UARB and would need to provide that the ratepayers of Nova Scotia were not prejudiced by this arrangement.

The recommendation that the UARB oversee the solicitation process is intended to allow it to determine its level of direct involvement. It is expected that the UARB, lacking sufficient expertise on its own staff, would obtain expert assistance in the solicitation process, from writing the RFP, setting the evaluation criteria, and performing the evaluation. NSPI is an obvious source of such expertise, but would then be subject to concerns regarding conflict of interest. The EMGC did not make a recommendation with respect to these matters; it felt that the UARB should decide what resources it needs and how best to acquire them.

In addition to the process, the EMGC made a recommendation on the UARB's evaluation criteria, to ensure that it takes account of important non-cost factors in evaluating proposals for new resources.

Recommendation 13

The EMGC recommends that the UARB consider emissions impacts and thermal efficiency in its review process for new resources.

Finally, the EMGC attempted to forestall any other possible conflicts of interest within NSPI. One example can be cited. During the solicitation process for new supply, proponents of generation will need system impact assessments to determine whether their proposals can be accommodated within the existing transmission system. Such assessments will be performed by the system operator function within NSPI, which must have precise details of the proposed generation in order to complete the assessment. If the generation unit of NSPI has access to such data, it would have a distinct advantage over the other proponents. The EMGC is aware that communication between individual parts of NSPI will be governed by a code of conduct, but wanted to ensure that this, and other potential examples of conflict, need to be covered by the code. Therefore, it adopted the following recommendation.

Recommendation 14

The EMGC recommends that the Standard of Conduct for NSPI ensure that confidential information obtained by NSPI in its role as transmission provider during an RFP process for new capacity not be shared with employees of NSPI's Generation business unit or its affiliates.

5.4 EMGC CONCERNS

The EMGC wished to record several additional issues regarding the process for new supply.

The committee's first concern centred on the fact that assumption of responsibility for the new supply process will require the UARB to obtain expertise that it does not presently have. A possible solution will depend on a wide range of considerations including risk, cost, environmental impacts, impacts on the transmission system, and others. Selection from competing proposals also demands considerable evaluation with necessary attendant skills to do so. Presumably the UARB will not need this expertise on a continuing basis, since the need for decision-making will be intermittent. On the other hand, without sufficient technical expertise the decision process almost certainly would be delayed and deliver less than optimal results. Therefore, the UARB will require sufficient financial resources to acquire and use appropriate expertise as needed.

A second concern dealt with risk sharing or how to properly evaluate differing degrees of risk assumption. A key issue in any electricity restructuring process is the sharing of the risks inherent in electricity supply. Because electricity production facilities have long lead times and even longer lives, the amount of risk can be higher than for other forms of production facilities. In a regulated market, the consumer takes most of the risks. In a competitive market, the consumer takes fewer risks but can be exposed to greater price volatility. In a bid process for new supply to a regulated entity, the proponents typically expect that the consumer will ultimately take most of the risks.

The PPA should spell out how the risks are to be shared. The major ones include

- capital cost risk,
- technical performance risk of the electricity supply facility,
- fuel price risk,
- environmental cost risk, and
- demand risk.

The first four items influence the cost of production while the last affects the need for electricity. While the PPA should indicate the general approach to risk, bidders can choose to propose different degrees of risk sharing.

In general, controllable risks should be assigned to those parties best able to control them. In general, the proponent should absorb the capital cost and technical performance risks, and devise various approaches to the sharing of fuel prices, and other risks. The UARB will need to be cognizant of the need to trade off risk against potentially important considerations. While not making any specific recommendation in this area, the EMGC did want to record its understanding that risk sharing will be an important part of the consideration of acquisition of new supply or demand side resources.

6.0 Transmission Issues

6.1 IMPORTANCE OF TRANSMISSION

Access to transmission is the key to effective competition in electricity supply, and the transmission system is the essential channel for moving electric energy and associated ancillary services. The EMGC deliberations incorporated issues of immediate interest to Nova Scotia Power Incorporated (NSPI) in the development of its transmission tariff. This, in turn, led to in-depth discussions on the issue of tariff design and eventually to the more detailed questions like cost allocation and billing determinants.

Giving Nova Scotia customers transmission access requires a major change in pricing electricity service. Nova Scotia rates are now bundled, which means that the customer buys electricity, ancillary services, and transmission and distribution services for one inclusive price. To allow transmission access, transmission prices must be separately identified under a transmission tariff. With the transmission tariff unbundled, generation rates must also be separately identified.

To implement transmission price unbundling, the EMGC adopted the following recommendation.

Recommendation 15

The EMGC recommends that NSPI develop and file a transmission tariff.

The crucial aspect of transmission access is that it must be non-discriminatory; that is, the transmission provider must treat all transmission system users (including its own generation or distribution affiliates) in exactly the same way. Potential wholesale users and/or competitors should not be arbitrarily precluded from the market by the lack of access to transmission or resulting from the administration of a tariff.

The EMGC agreed with this basic requirement of transmission tariff design in adopting this next recommendation.

Recommendation 16

The EMGC recommends that any transmission tariff developed for use in Nova Scotia ensure open and non-discriminatory transmission access for all market participants.

6.2 TRANSMISSION TARIFF OPTIONS

Before considering Nova Scotia, it might be useful to once again consider the most commonly used framework for the provision of transmission service in North America, the Federal Energy Regulatory Commission (FERC) Open Access Transmission Tariff, contained within Orders 888 and 889. The purpose of these orders was to force transmission owners under FERC's jurisdiction to offer non- discriminatory access for any parties wishing to make electricity sales transactions. A central part of this approach was the requirement that all transmission service providers regulated by FERC create and file for approval an Open Access Transmission Tariff (OATT) within a specified time. FERC Order 888 contained a *pro forma* tariff, which transmission providers could adapt for their systems. An important feature of the OATT is that it makes transmission procedures and costs transparent. The ultimate goal of the FERC initiative was to encourage competitiveness in electricity markets in the United States.

The impact of FERC Orders 888 and 889 has also been felt in Canada. A majority of Canadian Provinces have implemented FERC compliant OATTs in response to the US requirement for reciprocity. Many Canadian entities now offer open access transmission service comparable or superior to that offered by US transmission providers, although not all Canadian tariffs or market rules governing transmission services are alike.

Following is a summary of Canadian provincial participation:

- BC Hydro has a wholesale Transmission Services Tariff that uses the FERC Order 888 pro forma basis for its structure and content.
- Although Alberta does not have a FERC Order 888-type open access transmission tariff (OATT), it has a made-in-Alberta open access tariff that satisfies FERC's comparability/reciprocity provisions.
- SaskPower has posted a modified FERC Order 888 pro forma tariff OATT that provides U.S. and Canadian wholesale customers non-discriminatory access to the transmission system.
- Manitoba Hydro has an OATT and a Coordination Agreement with MISO (the midwest independent system operator) on file with FERC that requires Manitoba Hydro and MISO to have comparable, non-discriminatory access, transmission service charges and congestion management procedures.
- In an order dated September 26, 2002, FERC found that Ontario's Independent Market Operator (IMO) provides open access transmission service on a comparable, non- discriminatory basis for wheeling through and out of Province.

- FERC has recognized Hydro Quebec's TransEnergies (Quebec's functionally separated transmission entity) OATT as being comparable to that offered under FERC Order 888.
- In July of 2002, NB Power filed with its regulator an application for a FERC Order 888 compatible OATT. New Brunswick Power's OATT is presently approved and awaiting implementation, which is currently expected to be September 2003.

Significant additional infrastructure and administration changes are required with the adoption of a FERC OATT. FERC Order 889 requires that transmission providers functionally separate their transmission operations from their generation business. This is to prevent the affiliated generator from gaining an advantage through access to operational information or to the transmission system. Order 889 also requires the creation and administration of an Open Access Same-time Information System (OASIS). This is an internet-based platform for posting information on transmission system status, available capacity and pricing. Transmission customers, including affiliates of the transmission provider, are required to use the provider's OASIS to obtain relevant information and to book service.

Costs estimates for a Nova Scotian OATT and OASIS ranged between $1.8 and $9 million. Given these costs, serious consideration was given to whether an OATT would be required at this early stage in the development of the Nova Scotia market.One possibility would be to implement an OATT, but not an OASIS, thereby deferring the latter cost. It could be added later when sufficient generation, or an increased level of contestability, warranted it. An OASIS is an important tool to ensure that transmission access is non-discriminatory, and the absence of this capacity will very likely be viewed unfavourably by potential developers of new generation. To provide merchant generators additional comfort to undertake this market risk, formal criteria could be defined to identify the threshold appropriate to implement an OASIS.

Another option, to keep costs low while providing essential service, would be to discuss the possible sharing of the New Brunswick OASIS with its system operator for scheduling transmission in Nova Scotia. Since little congestion is anticipated in this province, at least initially, it might be possible, with little additional cost, for the New Brunswick OASIS to also schedule transmission in Nova Scotia. Scheduling transfers between the two provinces might also offer advantages if done through the New Brunswick system, since a Nova Scotia user of the interconnecting lines must also use the transmission system in New Brunswick.

The open access tariff conditions New Brunswick set for reciprocity with Nova Scotia have recently been clarified. The New Brunswick Board of Commissioners of Public Utilities (PUB) has approved the NB Power OATT. Under the PUB decision, Nova Scotia utilities will have access to the New Brunswick transmission system. To meet reciprocity requirements, Nova Scotia has until January 1, 2005 to put in place a transmission tariff offering open access to its transmission system.

Conditions in the United States are also changing. In July 2002, FERC issued a Notice of Proposed Rulemaking (NOPR) that is intended to eventually bring about a standard market design (SMD) in all markets under its jurisdiction. The NOPR contains a modified *pro forma* tariff. Implementation of the SMD NOPR has been delayed by negative reaction to it from several stakeholders, including state regulators and regional interests, principally in the Southeast and Pacific Northwest. On April 28, 2003, FERC issued a *White Paper* in which it described some of the elements it intends to include in its final rule. The *White Paper* shifts nomenclature to a Wholesale Power Market Platform from the SMD. It allows utilities to remain vertically integrated, but they must join either an ISO or an RTO. It also allows for more regional variation in implementing the market design, both in its features and in it's timing.

Although FERC still faces opposition to its planned regulation, its push towards greater regional integration of markets and transmission systems is going forward. Pressure on Nova Scotia from the United States will continue to be in the direction of reciprocity, including open transmission access, and in the direction of more integrated regional electricity markets.

The EMGC's discussions of the Nova Scotia transmission tariff took place in the context of the external pressures noted above and in Section 3.0 and the decision on market scope (see Sect 4.1). The EMGC concluded that the Nova Scotia market and its associated transmission tariff should develop in an evolutionary manner. The table below summarizes committee discussions regarding the starting point and direction for future changes in the design of a transmission tariff for Nova Scotia.

Movement through the chart can be viewed as tracking the evolution of the Nova Scotia system. The initial position is at the top left-hand corner with change expected to occur from top to bottom and left to right, or generally from top-left to bottom-right.Each step, or increment in complexity, would require additional administrative support and regulatory burden. Associated costs would be transferred to the system users. The consensus view of the committee was that each increment of change would come about as the appropriate response to a provincial need.

Meeting Needs	**Nova Scotia Solution**	**Maritime Solution**	**North East Solution**
Minimal changes by government edict	Y	Y/N	N
OATT, NS/Maritime	Y	Y	N
OATT, FERC 888 compliant	Y	Y	Y/N
OASIS when constraints exist	Y	Y	Y
FERC SMD	Y	Y	Y

As to a possible transmission tariff for Nova Scotia, the EMGC considered three possible options, which are listed below. When the tariff is finally completed, it will be subject to approval by the UARB.

Rate Option

An alternative to an OATT would be for NSPI to design a transmission tariff of its own, including rates for access to the system. Such an option would have NSPI determine terms for transmission to allow competitive generation. This rate option would not be compatible with FERC criteria for open access, since the terms of access would be controlled by the transmission owner and may not be transparently available to all potential transmission users. Also, it is uncertain whether this option will meet reciprocity requirements from New Brunswick.

FERC Order 888 option

This option would create an open access transmission tariff (OATT) in Nova Scotia that followed the *pro forma* approach provided in FERC Order 888. This option had two variants, one with an OASIS and one without. The second variant would not be fully FERC compatible.

FERC Standard Market Design option

This option would embrace a tariff with all aspects of the Standard Market design (SMD) contained in the FERC NOPR, described above. Several aspects of this approach make it impossible to implement in Nova Scotia at the level of restructuring envisioned by the *Energy Strategy*. The most important issue is the nature of the electricity markets. SMD markets have real-time bid-based wholesale pools with security-constrained least-cost despatch. In addition, the SMD includes locational marginal pricing (LMP). Under LMP, the prices at different locations in the electricity system depend on the marginal costs of supply at those locations. Neither of these features is consistent with the *Energy Strategy* commitment of gradual opening to competition.

The EMGC recognized that, for the Nova Scotia open access tariff to be effective, it would require some mode of scheduling and information. The Committee also recognized the effect of the external pressures on the Nova Scotia electricity supply system. However, the Committee did not want to force adoption of more expensive options until they are necessary. The recommendations below implement that approach.

Recommendation 17

The EMGC recommends the development of a transmission tariff for Nova Scotia that should initially include a scheduling and information system that need not be an OASIS.

Recommendation 18

The EMGC recommends that transmission tariffs in Nova Scotia develop towards eventual FERC compatibility.

In keeping with its desire to avoid unnecessary investments, the Committee felt that Nova Scotia should minimize costs of any OASIS, hence the following recommendation.

Recommendation 19

The EMGC recommends that, when an OASIS is required to facilitate the reservation of firm and non-firm transmission, together with the associated functions of publication, scheduling, etc., the transmission provider seek ways to minimize its cost, including purchasing OASIS service from another jurisdiction which supports an OASIS.

6.3 TRANSMISSION SERVICES OFFERED

Transmission service need not be an undifferentiated product. The transmission customer[10] can obtain service on either firm or interruptible bases.[11] They can obtain service related to specific transactions or they can use the entire grid. Customers can expect to pay different rates for different levels of service. However, whatever the tariff, electricity flows will obey the laws of physics and a contract that nominally involves a specific path will affect flows in other parts of the transmission system.

Transmission service is usually identified as either network, which uses the entire grid (also referred to as Network Integration Service), or point-to-point. A network service customer could, for example, be a municipal utility receiving electricity from several generating stations. Network service is firm; it can only be interrupted due to loss of some component of the grid. Point to point service, as the name implies, concerns the transmission of electricity from one specific location on the grid to another. This service would generally apply to a single large customer buying power from a single generation plant, or to import or export transactions on the intertie.

FERC Order 888 pro forma contained provisions for both network and point-to-point service. In Order 2000, FERC recognized that point-to-point is inherently an inferior service. After some discussion, the EMGC concluded that offering point-to-point transmission service within Nova Scotia might produce additional costs without any commensurate benefits. For export or import transactions, point-to-point service will be necessary. To recognize these facts and potential transmission products, the EMGC adopted the following recommendation.

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[10] In most systems, loads are identified as the transmission customers.

[11] All transactions are subject to interruption, if necessary to protect the integrity of the transmission system; firm transactions can only be interrupted for such reasons.

Recommendation 20

The EMGC recommends that transmission services that are to be offered under the transmission tariff should initially include:

- *Network Integration Service for the delivery of both capacity and energy for the supply of load located within the Nova Scotia control area*
- *Point-to-Point service for the reservation of transmission capacity from a specific point of receipt to a specific point of delivery for transactions involving imports into or exports from Nova Scotia. (Point-to-Point service would be offered on both a firm and non-firm basis).*

The above recommendation is not intended to exclude point-to-point service within Nova Scotia, but rather to avoid mandating it so that later decisions can reflect Nova Scotia's need at the time. The New Brunswick transmission tariff includes point-to-point service. The EMGC believes that the provisions of the Nova Scotia transmission tariff, in this respect as well as others, should be discussed with stakeholders both inside and outside the Province before the tariff is filed with the UARB. If, during the course of these discussions, a need for point-to-point service is identified, it could be included in the tariff.

Selling ancillary services to the transmission provider can be an important source of revenue for new entrants or other competitors. The process of acquisition of ancillary services should therefore be open to competition. In general, the transmission provider will contract for ancillary services in advance, pay generators for providing them, and pay an agreed energy price when generators providing operating reserve are called upon to run. The EMGC wanted to ensure that the transmission provider used a competitive system to acquire ancillary services, both to keep down the costs of the services and to allow an opening for competitive generators to provide them.

Recommendation 21

The EMGC recommends that the transmission provider acquire ancillary services from market participants at least cost possible, including by competitive contract processes.

Energy imbalances inevitably arise in a bilateral contract market. An energy imbalance is the difference between the amount that a market participant is scheduled to inject or withdraw and the amount it actually does inject or withdraw. Imbalances arise because forecasts can never be precisely accurate. The system operator (transmission provider) must constantly adjust the system to account for these imbalances. Energy imbalance service is treated as an ancillary service, priced and settled by the transmission provider, as indicated in the recommendation above. Imbalances are priced only on cost if they are small, and assumed to be inadvertent. Large imbalances are typically priced on a penalty basis, reflecting the assumption that the market participant deliberately relied on the system, rather than control its own facilities. Prices and penalty terms for energy imbalance service can be an important part of the costs for IPPs. The EMGC expressed its concern that energy imbalance pricing be based on the cost of the imbalances at the time they are incurred. Therefore, it adopted the following recommendation.

Recommendation 22

The EMGC recommends that the transmission provider offer an energy imbalance service based on costs, as approved by the UARB.

An important part of electricity supply is the provision of ancillary services, which are required for the operation of an interconnected electricity supply system.For example, one ancillary service is automatic generation control (AGC), which is the ability to follow (without manual intervention) small fluctuations in user requirements (load). Load varies constantly throughout a day, as individual consumers turn appliances and other devices on and off. Since electricity cannot be stored, the amount being generated must exactly follow the amount being used. The provision of an AGC service requires a generation unit that can be automatically controlled for small variations in output. Having AGC is essential to the operation of the electricity supply system.

In a vertically integrated system, ancillary services are provided by the integrated utility as part of their bundled services. There is no need to provide them independently, or to price them separately. The utility operator typically designs the system to meet the requirements for both energy and services, optimizing for their mutual provision. However, the functional unbundling of transmission from generation also separates acquisition of and charging for ancillary services. Further, in a fully competitive market, provision of most ancillary services can be a source of competition.

In Order 888, FERC specified two kinds of ancillary services to be offered by all transmission service providers: mandatory and voluntary. Mandatory services are inherent in the system operator function and must be purchased from the transmission service provider. These include: scheduling, control and dispatch, reactive supply and voltage control.

Voluntary ancillary services are: energy imbalance service, regulation and frequency response service, and operating reserves (including spinning, 10-minute, 30-minute and supplemental). These services can be self-provided, bought from other market participants, or provided by the transmission service provider. In any case, they are all necessary for the proper operation of the system.

Under an OATT, the transmission service provider offers all of these ancillary services. The EMGC agreed that that should also be the case in Nova Scotia.

Recommendation 23

The EMGC recommends that the transmission tariff require the system operator to offer each of the following ancillary services:

- *scheduling, control and dispatch*
- *reactive supply and voltage control*
- *energy imbalance*
- *regulation and frequency response service*
- *operating reserve - spinning reserve*
- *operating reserve - supplemental*

During discussions of the transmission tariff the EMGC recognized that a simpler design than that in the FERC *pro forma* might be appropriate for Nova Scotia, but that such a decision could raise issues with stakeholders inside and outside the province. The following two recommendations express the Committee's intention to simplify the tariff where it is preferred to do so.

Recommendation 24

The EMGC recommends that NSPI should give consideration to simplification in its tariff development, including point to point service and self-supply of ancillary services

Recommendation 25

The EMGC recommends that NSPI should consult with stakeholders in the consideration of tariff simplification

6.4 TRANSMISSION TARIFF DESIGN ISSUES

The principles of transmission tariff design are the same as those for any regulated rate design. They should ensure that rates are sufficient to recover the costs, including normal profit; they should assign costs whenever possible to those responsible for causing them; they should be transparent and they should be fair.

In addition to these general criteria, FERC enunciated six objectives for the design of an Open Access Transmission Tariff:

1. *Simplicity* – the tariff should not be unnecessarily complex
2. *Pricing Efficiency* – it should include locational pricing where possible
3. *Stability* – it should have predictable results over time
4. *Competitiveness* – should be encouraged with neighboring utilities
5. *Fairness* – it should provide non-discriminatory access to all users
6. *Flexibility* – it should possess the capacity for change, as warranted

Transmission pricing is generally designed to avoid favouring one market participant arbitrarily over another. It is also used to avoid the creation of artificial barriers that might discourage construction of new generation capacity. Meeting these simple conditions can be difficult, given the technical complexity of a transmission system and the need to ensure reliability of supply. Transmission costs are part of any electricity sales transaction. Transmission tariffs should reflect costs imposed on the system by the user. If the transmission costs are artificially high or low, they lead to artificially high or low prices to the customer of the traded electricity, and therefore to a distorted allocation of resources.

For example, radial lines that exclusively serve specific generation are as much a part of the cost of that generation as are the turbines. Assigning the cost of such lines to general transmission costs, as opposed to tying them directly to the specific generation, forces all transmission users to pay the costs. In effect, such assignment forces one generator to pay part of its competitor's costs. That puts competitive generation at an artificial disadvantage.

The EMGC considered several transmission tariff issues, some of them at the request of NSPI for guidance in the development of its forthcoming transmission tariff. Among the issues discussed were: the identification of facilities whose costs should be included; the identification of services that would be offered; establishing criteria to allocate revenue requirements associated with those services; establishing billing determinants; defining how congestion on the network would be managed; clarifying the method of pricing and finally allocating interconnection access with other jurisdictions. Each of these issues is dealt with in the following sections.

6.4.1 DEFINITION OF TRANSMISSION AND DISTRIBUTION

NSPI operates both electricity transmission and distribution systems in Nova Scotia. Their costs must be separately identified for an unbundled transmission tariff. In the United States, FERC issued a series of tests to be applied to various wire assets in order to determine whether they belong to the distribution or the transmission system. None of these tests is a single "bright line" assessment, i.e., one single criterion that can be applied definitively, to provide a clear and sharp distinction. Nonetheless, it is generally agreed that the seven characteristics[12] normally listed do represent a reasonable methodology for the required separation

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[12] The seven indicators for distribution assets are: 1. Facilities are normally close to retail customers; 2. Facilities are primarily radial in character; 3. Power flows into, but rarely, if ever out; 4. Power enters but is not reconsigned or transported; 5. Power entering is consumed in a close area; 6. Meters exist at the interface; and 7. Distribution will be at reduced voltages.

6.4.2 DEFINITION OF TRANSMISSION – RADIALS

Within a transmission network, some lines are considered to be radials, extensions connected to the main system at one end and to a major electricity user or generator at the other. They principally serve that user or generator. An important question in rate design is whether the costs of such radials should be borne by the entities they serve, by all transmission users, or by that group of customers served by similar connections

A general principle of rate-making for electricity is that parties imposing costs on the system should pay those costs, where such parties can be identified. Against this general principle should be weighed considerations of fairness and equity. One fairness consideration is that distribution customers should not be advantaged or disadvantaged by the nature of the transmission line serving them.

Radial lines usually serve either generators or distribution customers. Where a radial line ties a generating station to the grid, the cost of that line can be assigned to the station, since the cost of the line is as much a cost of generation as the cost of the station itself. A more complex situation is that of radial lines serving distribution.Before the creation of a transmission tariff, rates did not distinguish between transmission and distribution. Today, in some cases where the FERC tests are used, the distinction is clear. However, the case for radial lines serving distribution alone or distribution and generation is much less clear.

NSPI gave the EMGC transmission system maps (see appendices D-F) that proposed which lines should be classified as radials and which should be considered as part of the bulk transmission system. NSPI also suggested some 69kV lines that could be classified as transmission and others as distribution. Radial 69kV lines serving only one load/customer should be grouped with distribution, rather than generation.

Because of an historic anomaly, some parts of the transmission system in Nova Scotia include the 69kV level. The system was built at that voltage to serve load as well as to connect generation to the grid. Several Nova Scotian communities are served by radial 69kV transmission lines of considerable length that have no other transmission related function. Therefore, the committee considers them to be part of the distribution system. The annual revenue required to support these radials is about $6.9 million. Most supply NSPI distribution but some supply municipally owned utilities. Charging the costs of these radials directly to the communities involved would create rate differentials between NSPI customers and possibly disadvantage some municipal utilities.

Some equipment is required to properly connect generation to the grid. This equipment includes step-up transformers to raise the voltage to that of the transmission connection and some terminal structures that connect generation to the grid. At issue is whether these costs are assigned directly to generation, or to transmission costs in general. The result of the assignment of these assets to generation is included in the table below, which shows the impact of removal of several components from transmission revenue requirements. Their removal from transmission costs would not eliminate these costs; it would just assign responsibility for their cost to particular users or generators.

COST IMPLICATIONS OF TRANSMISSION DEFINITIONS

Transmission Component	% of Transmission Revenue Requirement
Generation step-up transformers	2.2%
Radial lines serving generation	2.4%
Radial lines serving load	9.3%

After considering this information, the EMGC made the following recommendation, which removes all of the above components from the transmission revenue requirement. The EMGC chose to assign costs to those identified as causing those costs. At the same time, it recognized that strict application of this principle might unduly affect some municipal utilities.

Recommendation 26

The EMGC recommends using the following principles to determine whether the costs of transmission facilities should be included in the transmission tariff:

- *The cost of a transmission facility used solely by one party should be assigned or charged to that party*
- *The cost of transmission facilities that are not part of the transmission backbone should be directly assigned or charged to those parties that use them. The preferred alternative for realizing this objective is:*
    - *Costs for radial lines serving generators be assigned to those generators*
    - *Costs for generation step-up transformers be assigned to those generators*
    - *Costs for radial lines serving distribution loads be assigned to distribution, the revenue requirement to be recovered uniformly from all distribution level customers, supplied by both NSPI and the municipal utilities.*

6.4.3 CHARGE DETERMINANTS

An important early step in transmission tariff design is the definition of charge determinants.[13] In keeping with the principle of assigning costs to those responsible for causing them, transmission tariffs are usually based on peak loads. Load customers are viewed as having caused the need for the transmission, so they are typically responsible for transmission costs.

Charges could be based on peak demand or on energy usage. However, the fixed costs of the transmission system are clearly linked to peak demand on the system. The transmission owner must build and maintain a system large enough to accommodate expected electricity flows at peak times (including sufficient reserve to withstand unplanned system demands). At all other times, the transmission system will have excess capacity.

A given transmission system can accommodate a wide range of energy flows; its size is determined by the peak load.Basing transmission charges on energy usage alone would not correctly assign costs to those responsible for causing them. Since cost is directly linked to peak load, the charge determinant for transmission is the customers' peak load. Peak load charge determinants can be measured either during the customer's peak or during the system peak. Measurements made during the former are called non-coincident peaks (NCP), because the customer's peak demand will not generally coincide with the system peak demand. Measurements made during the system peak demand are referred to as coincident peaks (CP).

The other major issue regarding charge determinants is the interval over which the peak is measured. Any interval can be selected but the longer the period, the longer the customer's exposure to a rate based on that peak. Basing transmission tariffs on an annual peak would cause the customer to pay an annual rate based on only one incident of high demand.

For point-to-point customers, charges are determined by their capacity reservation, which is proportional to their use of the system.

After some discussion, the EMGC agreed that an annual peak charge determinant would put too much emphasis on a single incident. Therefore, the Committee adopted the following recommendation.

Recommendation 27

The EMGC recommends that transmission revenue requirements be allocated based on the average twelve monthly coincident peaks.

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[13] A charge determinant is that characteristic of the customer's electricity use which will determine the charge. For energy purchases, the charge determinant is usually the quantity of energy. For charges intended to recover the fixed cost of maintaining capacity, such as those for the transmission system, the charge determinant can be peak demand. To be decided is how and when that peak demand will be measured.

6.4.4 BILLING DETERMINANTS – NET OR GROSS PEAK

Some transmission customers have the capacity to generate their own electricity. From the viewpoint of the transmission system they can be a generator at some times and a load at others. If such generators are large enough, system peak demand can vary significantly depending on whether or not they are generating electricity. Self-generators are often large industrial customers who have a need for both heat and power, and build plants to supply both.[14] Generation units in such installations sometimes experience outages resulting from periodic maintenance, equipment failure or simply because the production process may no longer require the heat portion of the generator.

The metered load for a customer with self-generation is its net load, that is, the total load minus any amount it is self-providing. The total load - that provided from the grid plus self-generation - is referred to as gross load. When the self-generator is operating, it is important to note, the customer is using more services from the grid than are indicated by its net load alone. As long as its generation is synchronized to the grid, it is receiving voltage control services. If its generator should fail, it can expect to receive power from the grid automatically, along with backup support.

The EMGC discussed the issue of appropriate charge determinants for such generators. A charge determinant reflecting only net load would permit self-generators to place costs on the system without paying for them. On the other hand, charges based on full gross load would result in payment for services that were never received.

One option might involve computation of charges over shorter time periods, since the charge determinant will then more closely approximate net load. Basing the charge on hourly net peak load will result in the self-generator paying for gross load only in those hours when its own generation is not operating. During those times it will take service from the grid. Alternatively, if the charge is set yearly, based on annual net peak load, the customer will pay for gross load in any year that its own generation was not operating, even for a short time.

The EMGC considered this to be an important issue. The *Energy Strategy* instructed the EMGC to recommend ways to encourage cogeneration. Under current tariffs, cogenerators pay on a net load basis. Making cogenerators pay transmission tariffs based on gross load would increase costs and negatively impact existing self-generators as well as act as a major deterrent to entrants.

A position between the two extremes of gross load and net load is monthly net peak load. With that charge determinant, a self-generator would pay for gross load only for those months when its generation was not operational. This would likely result in higher transmission charges for cogenerators, but less than that resulting from a full gross load tariff. Recognizing the potential impact on existing self-generators, the EMGC rec-

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[14] Such usages are called cogeneration – the combined production of electricity and usable heat.

ommended a different charge determinant for them.

The EMGC considered the cost implications of these charge determinants for customers with their own generation and adopted the following recommendation.

Recommendation 28

The EMGC recommends that the billing determinants to establish transmission charges for network customers be monthly net non-coincident peak demand and that for point-to-point customers it should be reserved capacity (estimated on a net load basis, if necessary.) The charge basis for existing self-generation customers would be hourly net non-coincident peak.

6.4.5 RATES – LOCATION AND VOLTAGE

The final issue considered for rate design is whether transmission charges should vary by customer location: either geographically within the province or electrically (i.e., in terms of the voltage level at which the customer is connected).

In general, the impact of geographical location on transmission costs is that the greater the distance over which electricity travels the greater the losses in the system. Most transmission tariffs do not recover congestion costs from existing loads, because of the difficulty of assigning such costs to particular loads. However, adding loads in regions distant from a source of generation will increase losses proportional to usage. Adding load in areas close to generation can decrease losses by allowing more distant generation to serve more distant loads. Transmission tariffs can recover expected additions to system congestion costs from prospective new generators or loads.

Multiple-transmission system organizations, such as Independent System Operators (ISOs) or Regional Transmission Organizations (RTOs), encompass the territory of more than one transmission service provider and eliminate transmission charges between them. That forces a choice between transmission service charge methodologies. The two choices are postage stamp rates, under which all transmission customers within the ISO or RTO pay the same rates, or license plate rates, under which each transmission customer pays the rate set by its own service provider, and then has access to the entire system.[15] Both approaches are in use. For example, the Pennsylvania-New Jersey- Maryland (PJM) ISO uses a postage stamp rate for all customers within the ISO; the New York ISO uses a license plate rate.

Given the transmission circumstances in Nova Scotia, the EMGC concluded that a postage stamp rate would be appropriate. The EMGC considered the question of whether the postage stamp rate should vary according to the voltage level at which the customer is connected. The argument advanced is that a customer connected to the system, at a high

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[15] This nomenclature comes from the obvious analogy with a postage stamp that costs the same everywhere in the country and will move a piece of mail to any destination within the country. A vehicle license fee is set by the issuing jurisdiction, but allows the vehicle to be driven freely anywhere within the country.

voltage level, is receiving no services from low voltage transmission or distribution; consequently they should not have to pay for them. An alternative view is that all transmission customers benefit from the entire system and its high degree of interconnectedness. Further, some Committee members felt that there is also the issue of fairness; if a customer is simply located close to a high-voltage transmission line, then they would have a much lower cost to access that line. Therefore, the Committee did not make any recommendation on whether transmission charges should vary with the voltage at which the customer is connected.

Because the incremental losses attributable to a large new transmission customer can be assessed at the time it is first connected, the EMGC recommended that new customers pay for such loss impacts. Such customers can make locational choices that may affect the operation of the transmission system. The following recommendation reflects current practice.

Recommendation 29

The EMGC recommends that the transmission tariff rate design be based on a consistent charge regardless of the location of the connecting customer, and that in addition new transmission customers be assessed locational factors relating to transmission losses, which may be negative or positive.

6.5 CONGESTION MANAGEMENT POLICIES

The phrase "transmission congestion" refers to the fact that, at some times, cheaper generation is available but cannot reach the load so more expensive generation must be used in its place. The cost of congestion is the difference between cheaper generation and the more expensive generation that is used. This situation can sometimes occur between provinces, when Nova Scotia has cheaper generation than New Brunswick but the lines between the provinces are fully utilized. The end result is that cheaper generation must be idled in Nova Scotia while more expensive generation is used in New Brunswick. The approaches used to address congestion internal to the province, as opposed to that which occurs on the interties connecting the provinces, are different and will be treated separately.

6.5.1 MANAGEMENT OF INTERNAL CONGESTION

One way to manage internal congestion is to have locational marginal pricing, with differential prices at different points in the system. The difference in price between two points at any time reflects the cost of the constraint to the system. That value changes constantly as supply and demand conditions change. Without a real time market, Nova Scotia cannot use locational marginal pricing.

Nova Scotia will therefore have a single pricing zone for transmission. Within that zone all participants can share congestion costs, or they can be assigned to the participant causing the congestion. Identifying which generator or user is causing congestion at any given moment is impossible. All participants in the system have the capacity to increase or relieve congestion simply by increasing or decreasing their usage. Therefore, when congestion occurs the cost incurred in a single price zone system must be shared.

However, at the time a new facility is attached to the system, it is possible to analyze the flow of electricity before and after its connection. That analysis can identify the potential for the new facility to cause congestion. If new congestion is predicted then the entity responsible could be required either to mitigate the expected impact, by adding any required system upgrades, or by paying additional congestion-related fees.

The EMGC adopted the following recommendations:

Recommendation 30

The EMGC recommends that all existing customers share the congestion costs on the existing system.

Recommendation 31

The EMGC recommends that new generators and major loads be required to pay:

- *All costs to connect to the transmission network.*
- *All costs of system upgrades required to mitigate congestion costs that they would otherwise create.Generators who agree to be constrained down if this alleviates the congestion to a level consistent with what previously existed will not be charged for additional congestion costs.*
- *Any direct transmission system benefits from the investments charged to the generator or load (e.g., reduced losses or reduced congestion costs that are borne by other parties) will be credited to the generator or load.*
- *Any direct benefits or costs due to the impact of the new generation or load on total system losses will be paid or charged to the new generation or load.*
- *The generator will be responsible only for the cost of advancing construction facility upgrades if the transmission service provider has previously identified them as required for reliability purposes.*

Another way to manage congestion, within a single transmission tariff zone, is through the creation and allocation of transmission rights. Transactions scheduled by the holder offirm transmission have priority on the transmission system, and will only be curtailed in the event of failure of some system element. The amount of firm transmission rights is limited by the capacity of the system.

The FERC pro forma tariff assigns the initial firm transmission rights to the existing customers using them, and also gives them a right to renew. This approach protects existing customers from losing rights they already have. The EMGC adopted recommendations following this practice.

Recommendation 32

The EMGC recommends that existing firm load customers within Nova Scotia be entitled under the open access tariff to firm Network Service,and that they have renewal rights to such service.

6.5.2 TRANSMISSION RIGHTS ON THE INTERTIES

Nova Scotia's only direct connection to another province is with New Brunswick. Those interprovincial connections, referred to as interties, are valuable assets, as demonstrated by Emera Energy's use of them to export power to Prince Edward Island. NSPI indicated to the Committee that transactions conducted over the interties reduce its annual revenue requirement by approximately $1.6 million. The EMGC felt that transmission rights on the interties should be explicitly allocated to transmission system users (existing Nova Scotia loads).

Recommendation 33

The EMGC recommends that Nova Scotia maintain a system of import and export transmission rights for electricity and capacity.

Access to the interties is important for the development of competitive generation in Nova Scotia. New generators in this province will probably want to export power, because the municipal market will not be large enough. Customers who can choose competitive supply may need to look to imports to find willing suppliers. At the same time, the EMGC recognized the heritage value of the interties, being used presently to facilitate exports whose profits reduce NSPI's revenue requirement.

At present, there is no explicit allocation of these rights; NSPI is the only party using them. However, in the future, the transmission tariff will identify how transmission rights on the interties are allocated. Their allocation could be left entirely to NSPI, or the EMGC could make a recommendation with respect to their allocation. A common method of allocation of intertie rights in an initial transmission tariff is to allow for an open bidding season. The EMGC did not make any recommendation as to allocation of the intertie rights although it does hold firmly to the view that the allocation process should be fair and open equally to all market participants.

6.6 SYSTEM OPERATOR FUNCTIONS

In a bilateral contract market, some entity must perform the function of system operator. The system operator's first responsibility is to ensure security and reliability of the system. In addition, it is responsible for scheduling the system and deciding on dispatch, for procuring and providing ancillary services and for scheduling transactions on the interties. All of these functions are required to facilitate the bilateral contract market. Therefore, the system operator role is central to the operation of the market. For this reason, system operator independence is one of the most important conditions for the operation of an effective electricity market.

In the bilateral contract market delineated in FERC Orders 888 and 889, the system operator is typically part of an integrated utility. It will be the provider of transmission services, responsible for creating and administering the OATT and the OASIS. As the transmission provider, it also performs the functions of system operator.

The transmission function of NSPI, following the completion of functional unbundling, is the logical entity to fulfill the roles of transmission provider and system operator. NSPI's transmission function will control the grid and, operate the system control centre. These functions are an essential part of the role of the transmission provider.

The EMGC recognized these roles with the following recommendation:

Recommendation 34

The EMGC recommends that the transmission function within NSPI be given the role and responsibilities of a Transmission Provider, including:

- *Create and file a transmission tariff*
- *Provide transmission service under the transmission tariff*
- *Provide ancillary services under the transmission tariff*
- *Operate the transmission system in accordance with the transmission tariff*
- *Be responsible for the safe and reliable operation of the electricity supply system in Nova Scotia*
- *Schedule transactions on the interconnections between Nova Scotia and neighboring jurisdictions.*

6.7 METERING STANDARDS

Metering is key to the proper administration of an unbundled transmission tariff and generation rates. As rates are unbundled, there is often a need for enhancedmetering capability. Some current meters on the NSPI system may not meet the standards required for the unbundled transmission tariff. Upgrading all meters on the system would be costly, and may not be immediately necessary. However, as meters come up for routine replacement or resealing, they could be replaced with higher quality meters.

Recommendation 35

The EMGC recommends that, as metering installations at transmission interfaces with generation, distribution or large customers are replaced or resealed, they should be upgraded or replaced by revenue quality interval meters.

7.0 Promoting Generation from Renewables

A declared principle of the *Energy Strategy* is that renewable energy sources will play an increasingly important role in electricity generation in Nova Scotia. Increased use of renewable energy will provide new business opportunities, improve the efficiency of the electricity system, and help fulfill Nova Scotia's commitment to a sustainable energy future.[16] Policies are needed to encourage promotion of greater electricity generation from renewable resources because oftentimes these alternate production routes are more costly than conventional power sources. Increasing renewable usage requires mandatory policies that establish standards, or voluntary policies that offer consumers the choice to pay a higher price for energy with lower environmental impacts.

One of the challenges facing utilities when attempting to integrate wind and similar power generation resources into the transmission grid is the non-dispatchability of these energy sources. Many types of generation, by their nature, are considered "non-dispatchable". Tidal power must be accepted into the system according to the cycle of the tides, although this can be accurately predicted and incorporated into a generation dispatch schedule. Wind turbines operate when the wind blows with sufficient strength and can be highly variable. Electric power from co-generation is sometimes considered a by-product of an industrial process, and follows a production schedule rather than a generation dispatch schedule. District heating systems may divert heat from the electricity generation process to meet local heating demand during times that are coincident with peak electricity demand. In addition to the variability of the power supply, generation can be non-dispatchable by virtue of being "embedded" in the system without sufficient control or communication infrastructure for the system operator to know when it is operating.

Many different generation sources are connected to the Nova Scotia electricity grid, most of which are under the dispatch control of the NSPI System Operator. The NSPI System Operator has operating agreements with significant non-utility controlled generators (over 2 MW) requiring them to notify the Operator when they are not available. Other small generators based on biomass, small hydro, wind and solar power currently amount to about 0.22% (5.057 MW) of the total installed capacity of Nova Scotia and do notappreciably impact the economic operation of the power system. Generation that is predictable but not controllable (such as tidal power) can be incorporated into a generation system without impact on a generation schedule. NSPI's experience with its own recently -installed commercial-sized wind turbines has suggested high penetration of this type of generation will provide new challenges to efficient system operation. It is generally acknowledged throughout the world that the effects of intermittency (particularly when the generation is non-dispatchable) are hard to quantify, particularly in markets adding new generation technologies such as wind. We shouldnote, however, that in some jurisdictions, the early concerns expressed by the system operator have ultimately been shown to be unfounded.

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[16] Energy Strategy, Volume 2, Part IV, pg. 1

Since demand for electricity is always variable, small amounts of non-dispatchable generation can be incorporated into the system without appreciable impact on economic system operation and reliability. However, as this form of generation increases, its impact will be increasingly felt. System load varies widely over any given day or year. Annual light load can be as low as 35% of peak load. Other jurisdictions have recognized the issues associated with high penetration of variable or non- dispatchable generation, and work is underway to better understand and articulate the penetration limits that may impact individual systems.

Design and implementation of transmission tariffs have not always had non-dispatchable or variable generation in mind. For example, the New Brunswick transmission tariff and market rules require NSPI to control interchange on the NS-NB intertie to a scheduled value. Thus controllable generation must be used to follow variations in output of non-dispatchable generation and load. This load- following capability is an ancillary service the system operator must purchase, and so increased need translates into increased costs to transmission customers. In many jurisdictions, where hydro is available, it is used to follow non-dispatchable sources.

7.1 RENEWABLES AND ELECTRICITY RESTRUCTURING

It is appropriate to link together environmental policy with electricity market restructuring. In other jurisdictions undergoing electricity restructuring, policies promoting generation from renewable resources have also been reviewed and refined. The restructuring process can have both positive and negative impacts on the use of renewables. On the negative side, changes in electricity pricingthat result from a shift away from regulation toward market forces, including greater price- competitiveness and cost consciousness,may, in turn, add to electricity suppliers's difficulties when attempting to roll the additional cost of renewables into their overall cost of service. On the positive side, as competitive retail markets offer consumers greater choice, they often choose to pay a premium price for electricity supply with lower environmental impacts.

7.2 EMGC ROLE IN RENEWABLES

The EMGC adopted the reduction of environmental impacts as a decision criterion. Following adoption of this criterion, the Committee tested its decisions to ensure that they did not have negative consequences regarding the application of renewables or low impact generation in Nova Scotia.

The *Energy Strategy* assigned the EMGC three tasks related to the promotion of renewable resources for electricity generation:

- Develop implementation plans for a voluntary green power marketing program;
- Determine a longer-term renewable energy portfolio standard (RPS); and
- Define "renewables" for policy purposes.

The Committee considered these and other measures that would promote the use of renewable resources for electricity generation in Nova Scotia. Specifically, the committee adopted two additional broad policies cited in the *Energy Strategy*:

- A voluntary target, to be eventually superseded by a longer-term Renewable Portfolio Standard; and
- Green Energy, with sellers of electricity, generated from renewable resources, having access to retail customers.

A renewable portfolio standard, or RPS, requires that some fraction of electricity supply come from sources defined as renewable. A green energy program permits sellers of energy using only renewable resources to offer electricity directly to end-use consumers.

A clear policy, capable of distinguishing electricity derived from renewable sources, must possess all of the following:

- a definition of renewable electricity;
- a method of certifying which facilities meet that definition; and,
- a method that permits monitoring of compliance with the definition and the facility that produces the electricity.

Each of these functions must be performed by an authorized entity, but not necessarily the same entity, for each function. An agency, or perhaps even a dedicated multi-stakeholder process, could define renewables. Once the definition is clear, other organizations (for example, an auditing firm) could certify facilities meeting the definition. Finally, a third entity could monitor compliance and output. Internationally accepted ISO certification is a useful example, where criteria are clearly spelled out, and several firms are capable of performing certification.

7.2.1 DEFINITION OF RENEWABLES

The EMGC dealt first with the issue of definitions and considered three possibilities:

- adopt a definition used elsewhere in Canada;
- adopt a definition used outside of Canada;
- create a definition specifically for use in Nova Scotia.

A nationally used definition for "renewable low impact" electricity generation in Canada is that offered by EcoLogo®. It is sanctioned by Environment Canada and administered by a private firm, Terrachoice. Some government programs, including specific federal purchases of electricity derived from renewable resources, rely on EcoLogo® certification to identify eligible sources.Because EcoLogo® is so widely accepted, certified renewable resources in Nova Scotia could readily qualify for sales in neighbouring jurisdictions.

The EcoLogo® definition of "renewable low impact" electricity generation was created through extensive discussions with stakeholders. The definition is comprehensive, lengthy and complex, running to 28 pages and covering not only the definition of the source (such as wind or water), but also the process for its approval and installation.

The EMGC has some concerns with the possible use of the EcoLogo® definition and process. First, its control by a private, for-profit company raised fears that the cost could become prohibitive for some generators. Second, tidal and wave power, existing and potential sources of renewable power in Nova Scotia, are not covered by the current EcoLogo® definition.

Despite these concerns, the availability of "off the shelf" definitions, which have been tested and accepted by others, led the EMGC to conclude that creating a uniquely Nova Scotian definition would be prohibitively expensive and time-consuming. It also felt that the adoption of a non-Canadian definition might carry the disadvantages of EcoLogo®, without offering the major advantage of consistency with other Canadian jurisdictions.

Having effectively accepted EcoLogo®, the Committee explored ways to mitigate its concerns. The EMGC secretariat contacted Terrachoice to assess the cost of obtaining and maintaining EcoLogo® certification. Additional information was also obtained regarding the ease with which EcoLogo® would be able to change the definition of low impact renewable generation to include tidal and wave power.

The EMGC recognized that certification of renewable generation facilities entailed a cost, and that it would likely vary inversely on a unit energy basis relative to the size of the generation facility. The EMGC preferred an approach that did not mandate certification by a specific third party. If a generator, using a renewable resource, wished to secure the perceived advantage of EcoLogo® certification, then that would be the sole responsibility and choice of the generator.

The EMGC agreed to adopt the Ecologo® definition, with the following recommendation.

Recommendation 36
The EMGC recommends that, for all public policy purposes relating to electricity supply, Nova Scotia adopt the EcoLogo® definition of renewable low-impact electricity.

When contacted, Terrachoice advised that the addition of tidal and/or wave resources to the definition of renewable resources for electricity generation would not be unduly difficult, expensive or time- consuming. Since these could be important sources of electricity in Nova Scotia, it was determined that a role exists for the Province to ensure that definitions are modified to accommodate the potential represented by these native resources. This recommended role would embrace support for both financial and human resources. Therefore, the EMGC adopted the following recommendation.

Recommendation 37
The EMGC recommends that the Province of Nova Scotia participate in a process to identify renewable resources of wave and tidal power and other new technologies as renewable low impact electricity under the EcoLogo® definition.

7.2.2 CERTIFICATION AND MONITORING

Programs requiring a definition also require certification that projects meet the definition. They also require monitoring to assure all parties that they continue to meet the definition and produce the energy for which they claim credit. The next step therefore was to identify agencies for certification and monitoring under the definition. The present agreement with Environment Canada gives Terrachoice the exclusive right to certify facilities that meet EcoLogo® criteria. So, if Nova Scotia chose to use a different method of certification it could not use the EcoLogo® name, nor claim EcoLogo® certification, even though an outside auditing agency had certified that the facilities met the criteria.

While recognizing the current monopoly held by Terrachoice, the Committee did not wish to preclude the province from authorizing some other agency, or from moving to another agency if it is deemed to be appropriate. The EMGC agreed that the adoption of the EcoLogo® definition for policy purposes will not always mean that all renewable generators have to be certified as meeting the EcoLogo® standard, only that they meet the Nova Scotia definition.

The EMGC also agreed that the EcoLogo® definition was preferred, as an off the shelf tested and accepted definition, but that Nova Scotia would be free to adopt its own means of certifying, recognizing that any such certification would not permit the renewable resource to be called EcoLogo®. The generator would be free to have its resource certified as EcoLogo® if it chose to.

Recommendation 38

The EMGC recommends that, for all public policy purposes in Nova Scotia, the Nova Scotia government authorize accredited companies or agencies to certify that generation facilities meet the Nova Scotia definition.

Once a facility is certified, it must be monitored to ensure that:

- its operation continues to meet criteria for low-impact renewables generation; and
- it is generating sufficient electricity to qualify for the credits it receives.

Terrachoice monitors certified generators for a flat rate plus a fraction of revenues, so EcoLogo® can, if necessary, perform the functions of definition, certification, and monitoring. However, consistent with its view that no single agency ought to have a monopoly on these functions, the EMGC did not recommend a specific agency for monitoring. It therefore adopted the following recommendation.

Recommendation 39

The EMGC recommends that, for all public policy purposes in Nova Scotia, the Nova Scotia government authorize accredited companies or agencies to monitor that facilities continue to meet the Nova Scotia definition and that sales levels of complying electricity do not exceed production supply levels

7.3 RENEWABLE PORTFOLIO STANDARD

The first policy application considered by the EMGC was the RPS. An RPS is normally stated in terms of a fraction of supply plus a timetable. For example, an RPS could mandate that 5% of total electricity supply come from renewable resources by 2010. Usually, the stated goal is achieved over a defined period, starting at a low percentage and gradually increasing over the planned duration. A competitive market for the development of new renewable generation should ensure that the lowest possible cost is achieved.

The *Energy Strategy* took a stepped approach regarding the introduction of an RPS in Nova Scotia. The Province should work with NSPI to implement a voluntary target for 2005, amounting to 2.5% of NSPI's current generating capacity, which would come from independent power producers using new renewable resources. The Province and NSPI should monitor the voluntary target during the three years from 2002 to 2005, before deciding whether to move to a longer-term mandatory renewable portfolio standard. The *Energy Strategy* did not assign the EMGC a role in the design of these programs. However, since the EMGC is a multi-stakeholder group dealing with Nova Scotian electricity issues, its members felt that the committee could make a useful contribution to the government by providing some advice on RPS policy choices, along with recommendations on the timing and scope of implementation.

Two fundamental matters were discussed, first, a review of the issues that are inextricably linked to the establishment of an RPS, and second, the question of whether a firm date should be recommended on which to implement the RPS. The committee chose to address both of these, simultaneously.

The issues that are considered unique to the discussion of a RPS are:

- The base level for renewable supply at the start of the RPS;
- Whether the RPS requirement identifies a share of energy or capacity;
- Definition of the rate of growth of the RPS fraction;
- Whether the requirement to meet the RPS target will be placed on loads or generators; and
- How the requirement will be met:
    - By direct contracts between Load Serving Entities (LSE) and Nova Scotian Renewable independent Power Producers, supplying renewable electricity;
    - By production of renewable electricity from new generation owned by Load Serving Entities; and,
    - By purchase of some renewable attribute by the LSE.

However, the first question was whether or not to recommend a mandatory RPS. The other issues followed on from that decision.

7.4 MANDATORY LONG-TERM RPS

The EMGC had extensive discussions on the question of whether or not to recommend a long-term RPS, given that the *Energy Strategy* committed only to three years of monitoring a voluntary RPS before making a decision on a firm program. However, the Committee felt that the EMGC was an appropriate body to decide the merits of a firm RPS, including elements of its design, and consequently considered those elements.

The *Energy Strategy* suggested that the premium price for electricity derived from renewable resources (under a mandatory RPS) could be borne by all NSPI customers, as part of the cost of service base.[17] The cost of an RPS, based upon the model proposed by the EMGC, would be determined by the amount of new certified renewable energy that is brought to the market. If new green energy in Nova Scotia is insufficient to meet the mandatory RPS, the cost to consumers will be high, equal to the penalty cost of non-compliance. If new green energy supplies are greater than stipulated by the RPS, the cost to consumers would be low, since suppliers will engage in competition with each other.

The EMGC, while defining the basic process for an RPS, leaves the determination of the amount of penalties for non-conformity to be established by a subsequent process. There is recognition that such penalties must be sufficiently high in order to encourage compliance. Additionally, the EMGC's RPS model accommodates the *Energy Strategy* intent of allowing Renewable Independent Power Producers direct access to customers, by allowing the trading of RPS tags to LSEs.

An issue that occupied considerable discussion was the question of the appropriate base level for the RPS. There are two alternatives: use the existing supply from renewable resources as the base level so that growth would be measured from that point; or, start with a base level of zero. The level of generation from renewable sources in Nova Scotia during 2001 (the year in which the *Energy Strategy* was released) was approximately 8.3% of total energy supplied to customers. The current (2002-2005) NSPI voluntary renewable energy initiative will add another 1.2%. If the RPS does not distinguish between existing and new generation, and a premium is paid for the electricity produced from existing renewable generation, consumers could be less likely to purchase electricity from new renewable generation, simply because of limited resources. Setting the RPS at a zero base avoids the problem of allocating any increase in value to existing assets but it also gives no recognition of the renewable energy produced by those assets. Conversely, to recognize existing renewable energy producers, without allowing them to generate RPS tags, would suggest to Nova Scotians, as well as other jurisdictions, that Nova Scotia does have a valuable, existing renewable energy generation pool.

As to how the RPS requirement should be stated, the committee considered expressing it as a fraction of total load in each year of the program. In some years problems could arise meeting this goal, since load growth in Nova Scotia can be lumpy. The system is small, and new industrial customers can bring a significant percentage increase to the system in one year, producing a sudden requirement for new renewable generation. Consequently, the EMGC concluded that it preferred to state the RPS requirement in terms of a starting level, median requirements, and a final requirement for 2010.

An RPS is generally stated as a percentage of either capacity or energy. Many renewable resources are not dispatchable and also have lower capacity factors than thermal generators. For example, wind power installations, run-of-the-river hydro generators and solar collectors depend upon the availability attributes of their respective energy sources. These attributes determine when the facilities will produce electricity.[18] An RPS based on capacity would likely embrace a higher number than one based on energy. Also, a capacity-based RPS would have the further disadvantage that generation from renewable resources could not be guaranteed, only that the capacity would be installed.[19] After considering RPS recommendations for both options the EMGC concluded that RPS targets should be stated in terms of energy.

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[17] *Energy Strategy*, Volume 2, Part III, Electricity, Pg. 17

As a review of the methodology used to determine how an RPS might work in Nova Scotia, several key revenue streams are identified that a renewable producer might seek in order to create an economically sound project:

Electricity – effectively "null" energy, to be sold with the green attributes either to an existing Load Serving Entity, or to any other customer;

Green Attributes – the "emission offsets" that accrue from the generation of certified low-impact electricity, either to an existing Load Serving Entity, or to any other customer; and,

RPS Tags – these tags would be tradable and would demonstrate that the certified green energy was produced in Nova Scotia. They carry no green attributes or electricity in and of themselves, but are the instruments that the LSEs would require to demonstrate that they were meeting the requirements of the RPS. The purchasers of the RPS Tags would be the LSEs and the cost of the tags would ultimately be incorporated into the cost of service by the LSEs.

The Committee additionally concluded that the creation of a system employing traded RPS tags would be preferable to requiring each responsible entity to own or to contract directly for power from renewable sources. A RPS tag is a certificate that identifies a quantity as having come from a certified renewable resource. RPS tags are a much more direct way of dealing with a green power supplier.

The requirement to meet the RPS will ultimately be placed on customers. In Nova Scotia compliance will fall to distribution companies, or, more properly, on their load serving function, as opposed to their distribution function. The former are called load serving entities, or LSEs.

The Committee adopted the following recommendations.

Recommendation 40

The EMGC recommends that the province of Nova Scotia adopt a mandatory RPS to take effect in 2006.

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[18] The capacity factor is the ratio of energy actually produced by the facility to the energy that the facility would have produced had it been able to operate at full capacity

[19] Although it is unlikely that installed renewable resources such as wind or small hydro would not be running when available, since they are likely to have the lowest operating costs, with zero fuel costs except possibly for royalties paid for the use of the water.

This and the following recommendations resolve many issues related to the design of an RPS. However, the EMGC recognizes that implementation and adoption of an RPS, as recommended above, will require a process for its further specification.

Recommendation 41

The EMGC recommends that electricity from renewable resources have RPS tags that can be created and traded separately from the electricity itself. The RPS tag is a certificate that a quantity of electricity has the attribute of coming from a certified renewable resource within Nova Scotia.

Recommendation 42

The EMGC recommends that entities responsible for acquiring electricity from renewable sources can acquire RPS tags by contracting directly with a certified generator or by purchase from other tag holders.

The next recommendation deals with the base, the target and the method of meeting the requirement. It chooses as a base the actual amount of energy generated from renewable resources in 2001, the year in which the *Energy Strategy* was introduced, and sets a requirement for 2010. The formula, used to achieve the target, was developed by making additions to the base amount. Initially, the RPS target was based on the assumption that new renewable generation would take up one-half of the projected load growth, in addition to satisfying the NSPI voluntary target of 1.2% by 2005. NSPI has already identified incremental energy requirements for 2008, so this new renewable generation will be projected into an environment already anticipating the need for new generation. NSPI projects average load growth to be approximately 1.5% per annum, so the RPS target was set at 0.75%. Having established 2001 as zero base, and included the voluntary target of 1.2% by 2005, additional renewable energy requirement established by the RPS is 0.75% per annum for years 2006 to 2010, for a total RPS incremental requirement of 3.8% of energy. Together with the voluntary target, the aggregate amount of renewable energy targeted for 2010 is 5% of all energy supplied.

Recommendation 43

The EMGC recommends that the province of Nova Scotia require each LSE to obtain RPS tags certifying that the fraction of its electric energy from renewable sources by 2010 is equal to the actual base of renewable electric energy at 2001 plus 5.0%.

Gradually phasing in the RPS requirement is a normal component of an implementation strategy. Setting the starting point for the mandatory RPS in 2006 creates some complications, because of unpredictability of renewable energy that will be constructed during the preceding voluntary period. However, the EMGC recognized that the practcalities of developing the amount of renewable energy sources contemplated by the RPS will necessarily drive a gradual development.

Recommendation 44

The EMGC recommends that, to encourage the development of a stable renewable energy sector, and meet the environmental goals established by the RPS, that NSPI be required to annually report to the UARB as to itsprogresstoward meeting its goals and thatthe UARB have the authority to issue directions to NSPI to ensure that these goals are met.

The EMGC recommends that, to encourage the development of a stable renewable energy sector, and meet the environmental goals established by the RPS, that the RPS require each LSE to obtain tags certifying that the fraction of its electric energy from renewable sources by 2006 be equal to the actual base of renewable electric energy in 2005 plus 0.75% and that that fraction increase to 3% by 2008.

The EMGC recognized that "RPS tags" would also require an "expiry date" or "best before date" to ensure that the expected environmental benefits would accrue to the citizens of Nova Scotia. For example, if an "RPS tag" was without an expiry date, an LSE could purchase tags in one year that could meet their requirements for any number of years. This clearly would not provide stability to meet long-term emission reduction targets.

Recommendation 45

The EMGC recommends that "RPS tags", obtained from certified Nova Scotia renewable generators, carry an expiry date set 18 months from the month of generation, by which time they will have been used by an LSE to meet the RPS requirement, or they will have lapsed.

To deal with the potential for windfall profits, the committee recommended that existing renewable generation be recognized as renewable, but that the renewable aspects be assigned to existing customers.

Recommendation 46

The EMGC recommends that the province of Nova Scotia recognize the heritage attributes of renewable generation that existed in December 2001.

Recommendation 47

The EMGC recommends that the tags relating to the output of the heritage renewable generators (2001 generation plus NSPI constructed or contracted facilities to 2005), which will be the base electric energy at 2005, be assigned to LSEs as at the RPS implementation date in proportion to their load share.

Since heritage generators will not receive any monetary benefit from the tags, the EMGC felt they should not have to pay to become certified. The Heritage tags" provided to the heritage generators, for production from pre-existing generation assets (prior to 2001) would be an acknowledgement of their importance to the Nova Scotia generation mix. These "Heritage tags" would be differentiated from the "RPS tags" in that they would not be tradable, nor require facility certification. The objective of the RPS is to encourage new renewable generation.

Recommendation 48

The EMGC recommends that existing renewable generators a) be exempt from any certification requirements by virtue of their heritage position; and b) that LSEs maintain their proportional rights to the tags from heritage generation.

Once heritage renewable generators are defined, they will be ineligible to sell additional tags unless any additional generation became available through major capital investment. The EMGC recognizes and supports the fact that existing (heritage) renewable generators shall have the right to participate in any external markets, based upon the export of generation to which they would otherwise be entitled.

Recommendation 49

The EMGC recommends that heritage facilities be able to create and sell new RPS tags to meet RPS requirements only upon becoming certified as renewable. The new tags would come from either a) incremental increases in production based upon expansion or technology upgrades; or b) the output of a facility that was significantly rebuilt in lieu of facility retirement.

Finally, new generators would normally be the agents to issue tags to meet the RPS requirement.

Recommendation 50

The EMGC recommends that new renewable generators within Nova Scotia, on-line after December 2001, be eligible to sell RPS tags to LSEs as the method of meeting the RPS targets.

7.5 GREEN ENERGY MARKETING PROGRAMS

Green energy marketing programs[20] operate on the assumption that energy from renewable resources comes with a higher cost than energy from conventional sources. Consequently, consumers who want this energy must be prepared to pay a premium for it. The design of a program to promote green energy depends on the organization of the market and the nature of the green energy initiatives. Depending on the specific green energy program the consumer premium can be mandatory or voluntary.

Green energy marketing programs can be distinguished from a renewable portfolio standard. Under_the proposed RPS, which is mandatory, a LSE, or distribution utility purchases RPS tags from certified Nova Scotian renewable generators, at market prices, and then spreads the additional costs across its entire customer base, subject to regulatory approval. The utility can either build the renewable generation facilities on its own to create these tags, or purchase RPS tags, discussed in more detail below.

In Nova Scotia, a retail green energy program would allow green energy sellers only, to sell to consumers who are willing to pay the green energy premium. In a fully competitive retail market, any seller could offer green energy at a higher price, but would face price competition from sellers with little or no green energy in their offerings. Consumers could then choose whether or not they wished to pay a green energy premium. Such a market would have no need for a specific program aimed at sales of green energy.

In Nova Scotia, where sellers get preferred access, green energy programs face the same issues of definition, certification and monitoring as described above for an RPS. Because the definition of renewables adopted by the Committee will apply to all public policy purposes in Nova Scotia, it would rule for green energy marketing programs. Monitoring of actual generation performance is crucial for marketing, because it ensures that the electricity is generated from low-impact renewables, and can prevent a seller from claiming credit for more green power than was actually generated. Employing one consistent definition of renewables greatly increases efficiency and reduces confusion.

Several remaining issues relating to the specifics of a green energy marketing program need to be considered. They include: which sellers would be eligible to offer green energy; what is sold and how; which customers should be eligible to buy green energy; whether the distribution utility should be required to offer billing services; and the role of NSPI in future green energy sales programs.

The purpose of the green energy marketing program is to encourage the development of new generation in Nova Scotia using renewable resources. To be specific about that objective, the EMGC adopted the following recommendation. It specifies that only sellers from new resources in Nova Scotia are eligible. In effect, it assumes that the Province does not have full retail competition, and that the green energy is sold to consumers who are willing to pay the premium.

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[20] In this report, the term A green energy@ will be used to refer to electricity sold as part of a specific program to offer improved customer access for IPPs selling power from renewable resources.

Recommendation 51

The EMGC recommends that any seller offering electricity from renewable resources using facilities constructed in Nova Scotia after 2001 be able to sell directly to electricity customers.

The next issue concerns the relationship between green energy buyers and sellers. In a physical bilateral contract market, the seller of green energy would have a contract to supply specific amounts of power to specific customers at specific times, which would be difficult and costly to implement. It could subject green energy sellers to high charges because of their inability to accurately forecast output from some renewable resources, such as wind.

An alternative approach would be to adopt a purely financial contract. With a financial contract, the buyer agrees to pay the seller based on mutually agreed upon conditions. Those conditions could include a fixed, regular monthly payment, representing the green energy premium on a block of electric energy over the month. The payment could be a variable amount, based on a premium per unit of energy consumption (kW.h). Whatever the basis, buyer and seller agree that the transaction is financial, so it does not necessarily depend on the actual timing of the electricity that the renewable generator will provide.

The EMGC adopted the following recommendation, which sets financial contracts as the standard but allows parties to go beyond that if they agree:

Recommendation 52

The EMGC recommends that sellers of electricity from renewable resources sell to electricity customers in Nova Scotia preferably on the basis of financial contracts, although physical contracts are certainly acceptable where the contracting parties can and choose to do so.

Assuming that the relationship between buyers and sellers will be financial, the EMGC considered whether to recommend that the distribution utility, which has direct customer access, provide billing services for the sellers of green energy. The committee noted that the distributor's billing service provides a benefit to any green energy seller. The customer pays only one bill for both green and regular energy, and the distributor can terminate service if the customer fails to make required payments. No independent billing system is able to attain that level of payment certainty. Giving competitive sellers of green energy access to distribution billing services would help create a competitive balance between them and distribution utilities.

Therefore, the Committee adopted the following recommendation that does not mandate an agreement between parties but rather suggests a process based on good faith.

Recommendation 53

The EMGC recommends that all electricity distributors in Nova Scotia should discuss access to their billing services in good faith with sellers of green energy, and offer such services on non-discriminatory terms.

The *Energy Strategy* states that NSPI should, with the Utility and Review Board, develop green energy rates for all customer classes. At this time, NSPI has received interim approval for a residential green energy rider. The EMGC discussed the future role of NSPI in offering green energy to customers but did not offer any recommendations on this subject. The Committee recognizes that NSPI has already launched contractual discussions for a project to develop renewable energy in Nova Scotia for supply to a specific large customer. NSPI eventually expects to offer similar programs to smaller customers, with the intention of being a major participant in this area. It should be noted that NSPI and other distributors enjoy a number of advantages over new entrants. They have strong consumer recognition, good will and regular contact with customers.

The EMGC had some concerns regarding two possible barriers to the development of green energy. The first is the potential for a system operator or transmission service provider to impose punitive costs on some kinds of renewables generation (such as wind and solar) as a consequence of their variability and relative unpredictability in output. Such renewable resources have to be treated by the system operator as special cases. For example, in a system where bilateral contracts have to schedule electricity injections two days in advance and the responsible party can be assessed penalties for large deviations, penalties could be heavy for some forms of green energy, where that degree of predictability is not possible. The terms that green energy generators get from NSPI will be negotiated between the parties.

The second possible barrier is the potential for an incumbent utility to impose unduly high connection costs on small-scale renewable generators. This can come about when connection standards are designed with large facilities in mind, and when performance standards and other measures are more exacting than necessary. A task force currently underway in the United States is developing a connection code that is likely to be applied widely in North America, presumably to include Canada as well. NSPI is currently working on an integrated approach for small generators.

Consequently, the EMGC adopted the following recommendation:

Recommendation 54

The EMGC recommends that transmitters and distributors in Nova Scotia adopt connection standards for small-scale generation that properly reflect the size and potential system impact of the facility.

7.6 NET METERING

Net metering lets customers with their own generating capacity move electricity into the distribution system when they have energy surplus to their own needs. On those occasions, their electric meters will run backwards. Consequently, at the end of a billing period the meter will only reflect the net energy drawn from the supplier. Net metering programs apply only to small generators who are connected to a distribution system, and who are seeking primarily to serve their own load. The Energy Strategy did not restrict net metering access to renewable sources, but it did mention wind, solar and mini-hydro as the most likely candidates. It also stated that NSPI would establish standards and other conditions for this issue. Therefore, the committee's function was to make recommendations to assist with the implementation of these plans. NSPI is currently working with equipment suppliers to develop a net metering policy, and it enumerated some benefits of such a policy.

The EMGC embraced net metering as an important additional tool to promote renewables, so it favoured limiting its application to those sources. The issues that were identified as important to net metering include:

- technology restrictions;
- limits on size of units;
- aggregate fraction of distribution utility supply limits;
- period for netting out;
- disposition of net energy generated (NEG), and,
- rules for connection.

In a net metering program, the distribution utility effectively buys power from the net-metered customer when its meter is running backwards (additional options exist but this is the most common). The price paid for that electricity by the utility is its full retail price, since the power is netted out against sales that would take place at that price. Clearly, the distributor loses money on these transactions, since there is no allowance for its costs. In addition, net meteredgeneration is generally considered to be non-dispatchable energy. Therefore, net metering programs typically face limits, both on the size of the individual generators and on the aggregate fraction of the host utility's supply that net metering can represent.

Any net metering application can produce net energy generation (NEG). That occurs when the total energy delivered from the generator is greater than the total taken from the distributor. The design of a net metering program must consider two questions that relate to this issue of NEG, namely, over what interval is the net energy calculated, and what is its eventual disposition? And, finally, some technical issues concern the conditions of linkage to the host utility, in terms of connection and metering standards.

To review net metering practice in other jurisdictions, the EMGC received a report surveying all states in the United States with net metering programs. That survey addressed most of the issues identified above, and showed that their practice varied across jurisdictions, which was useful when considering possible policy changes for Nova Scotia.

The committee prior to offering recommendations addressed several important questions. The first concerned eligibility for net metering programs. One issue is the actual technology that is employed, with a clear committee bias toward renewables. A second emerged from an earlier discussion, on the definition of renewables for public policy purposes, where the EMGC concluded that formal certification is not likely to be cost-effective for generators less than 100 kW. A third condition for eligibility is the technical compatibility of the net metering application and that of its host utility. These and other conditions between the utility and the net-metered generator would be contained in an operating agreement, approved by both parties. If the generator chooses not to be certified, the distribution utility would make the determination of whether it meets the criteria for renewable generation. These conditions are expressed in the following recommendation:

Recommendation 55

The EMGC recommends that a generator qualifying for net metering be one with a suitable interconnection and operating agreement, using renewable resources for generation.

NSPI's current policy for net metering, presently under review, sets an upper limit of 10 kW. A survey of practice in the United States showed that the largest eligible size is 100 kW (excepting California, where it is 1 MW). NSPI reported that potential generators with projects as small as 50 kW wished to negotiate power purchase agreements, since they are excluded from net metering under current rules. However, these projects are generally smaller than is desirable for a power purchase agreement, so that an increase in the maximum allowable net metering size would alleviate this problem.

Taking this into consideration, the EMGC approved the following recommendation:

Recommendation 56

The EMGC recommends that qualifying generators with installed capacity of 100 kW or less, connected to a distribution system, be eligible for net metering programs.

In addition to individual net metering size limits, the EMGC recognized that an aggregate limit was necessary in order to protect the interests of the distribution utilities. This limit could be placed on total net metering installations either as a fraction of the demand, or as a fraction of energy.

The following recommendation is consistent with practice in other jurisdictions and expectations from the distribution utility representatives on the Committee.

Recommendation 57

The EMGC recommends that no distributor in Nova Scotia be required to accept net metered installations having a total installed capacity of more than 0.5% of its annual peak demand.

The United States survey showed a wide range of practice in NEG. The period for netting and billing energy ranged from monthly to annual to indefinite carryovers. The treatments of NEG included paying the generator at utility avoided cost, paying at a premium to utility avoided cost, and letting NEG revert to the utility for no payment. The full retail rate paid for net metered energy represents a clear benefit to the net metered customer. Allowing NEG to carry over from month to month could also benefit the customer in jurisdictions with seasonal pricing. It allows the customer to over generate in months when electricity prices are low and receive full credit in months when electricity prices are high.

Given the benefit of net metering to the generator, the EMGC agreed to balance it off by having NEG revert to the host utility without payment. However, the recommendation uses a rolling 12-month netting period, as shown in the following recommendation. In effect, from the 13th month forward there is a monthly reset of the credits to zero for the first month. The recommendation also recognizes the role of the UARB in approving conditions that would affect rates.

Recommendation 58

The EMGC recommends that, subject to approval by the Utility and Review Board, excess energy delivered to the distributor from net metering installations can be carried over to subsequent billing periods, for up to 12 months. At the end of each rolling 12-month period, excess energy credits are set to zero without compensation to the generator.

The remaining topics address the technical standards for installation of generation facilities to be accorded net metering. Host utilities have a responsibility to maintain reliability and safety of their systems, and they must set minimum performance standards for net metering applications. These should not be made so onerous that they become a barrier to new net metering applications. For example, insisting on the same level of protective circuitry as for a large-scale generator would make net metering applications uneconomic. Such a technical requirement is excessive, given the limited potential for generation of net metered size to impact the reliability of the distribution system.

Net metered applications do need to meet system specifications. For example, if a distribution utility were to take a line out of service for maintenance, and that line was activated by energy entering the system from a net metered application, it might pose a serious safety hazard for the utility personnel.

The following two recommendations deal with technical standards issues for connection using net metering applications. They recognize the current NSPI discussions and reflect the awareness that technical standards must be reasonable relative to the size of the applications.

Recommendation 59

The EMGC recommends that NSPI expeditiously finalize the connection standard(s) currently under development for small generators connected to a distribution system.

Recommendation 60

The EMGC recommends that distribution utilities in Nova Scotia be required to adopt technical standards for net metering installations that properly reflect the size of the installation and its potential impact on the system. Because they will be constrained to use renewable energy sources, net metering applications in Nova Scotia could be eligible for emissions credits or allowances under a program to reduce air emissions in Nova Scotia, or under climate change initiatives. It might not be practical for net metering applications to get these credits, because of the requirement for certification and its cost relative to the small size of generator.

The EMGC considered the benefits that accrue to net metering installations:

- The generator is paid or credited with NSPI's full retail rate, without allowance for non- generation charges not incurred by the net metering installation
- The net metering policy will involve additional administrative activity on the part of NSPI, the cost of which is not recovered directly from the net metering installation
- The ability to use the grid as a balancing and storage mechanism

As an offset to the benefit net metering applications get from the host distribution utilities, the EMGC adopted the following recommendation.

Recommendation 61

The EMGC recommends that the host distributor be entitled to any emissions credits or allowances arising from the use of renewable energy sources to generate power in connection with a net metering installation.

8.0 Promoting Cogeneration

8.1 CHARACTERISTICS AND ECONOMICS OF COGENERATION

Cogeneration is usually defined as the simultaneous production of electricity and useable heat. Cogeneration installations can be industrial, commercial or residential, but are limited to locations with a heat requirement that can be met from heat recovered during electricity generation. The cogeneration site also typically includes one to several facilities that require electricity.

In general, cogeneration installations have higher conversion efficiencies than simple electricity generation, since a higher percentage of the fuel is converted to useful energy. For example, a simple coal-fired steam plant can have an overall conversion efficiency in the range of 35%, a simple cycle gas turbine can achieve slightly more than that, and a combined-cycle gas turbine can exceed 55%.[21] Some cogeneration applications have considerably higher efficiencies, some approaching 90%. Higher efficiencies result in less fuel being used to achieve the same end result, while simultaneously reducing environmental impacts.

The exact nature of the heat requirement can vary widely with the application. Many industrial processes, such as pulp and paper operations or petroleum refining, require high-pressure steam, and consequently can be very compatible hosts for cogeneration applications. A typical application might fit a combustion turbine with a heat recovery steam generator (HRSG) to create high-pressure steam. Overall efficiencies can be further improved if the residual heat energy can be used for other applications, such as space or water heating.

Additional cogeneration applications include industries such as: food processing, where steam or heat are used for cooking; hospitals and schools, where steam is used forheating; and district energy systems, that distribute heat through steam pipes to various separate buildings.

A key element in the economics of cogeneration is the appropriate and complementary sizing of the electrical generation component with that of the heat needs. If the generator can reliably produce sufficient heat to meet the needs of the steam host, it can reduce or eliminate the costs of other systems. However, electricity production rarely achieves an exact match with the load of the steam host. Shortfalls or surpluses must then be bought or sold offsite, respectively. Access to a market to permit this balancing can be crucial to the economics of the application. If shortfall prices are too high, or those for the surplus too low, the project could be uneconomic.

An additional economic consideration, like that of all on-site generation installations, is the additional cost of backup power and other ancillary services taken from the grid. This

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[21] A simple cycle gas turbine (SCGT) is one that burns gas in a turbine (somewhat like a jet engine) and uses the power to generate electricity. A combined-cycle gas turbine (CCGT) uses the waste heat from the turbine to make steam, and uses the steam to generate electricity.

service permits the cogeneration operator to draw on the grid in order to continue operating, in the event of either a planned or an unplanned outage.

Both of these conditions, along with too stringent standards or regulatory provisions that block cogeneration, have been shown to be important barriers, especially where an incumbent integrated monopoly utility sets the terms. Making cogeneration viable, therefore, may require a market with greater openness for electricity, or other supportive policy changes.

8.2 POLICY INITIATIVES AND COGENERATION

The Nova Scotia *Energy Strategy* encouraged cogeneration.[22] The rationale behind this encouragement is its higher energy efficiency and correspondingly lowers environmental impact.

The *Energy Strategy* does not provide anypolicy advantage to cogeneration over other independent power producers, because under the proposed new market structure any IPP should be able to sell power to NSPI. With the proposed new access policy IPPs should be able to sell to Nova Scotia's municipal utilities, and, if they acquire transmission rights, to export customers, as well.

Given the *Energy Strategy's* expressed preference for cogeneration, and the absence of any specific policy advantage, the EMGC concluded that it should explore additional avenues to promote cogeneration, and consequently gave considerable attention to this topic. In order to assist the committee in its deliberations, Navigant Consulting produced a Cogeneration Issues Paper that presented important background plus associated issues and listed some possible policy initiatives to promote cogeneration in Nova Scotia.

The Committee is aware that the market opening, defined in the market scope recommendation, is very narrow and may not encourage the entry of competitive generation in Nova Scotia. Also, encouraging cogeneration could produce some new generation that would compete directly with NSPI. Further, two potential cogeneration proponents made their interest known by letter to the Committee Chairman as well as through direct contact with Committee members.

NSPI has supported the effort undertaken by the EMGC to understand the critical success factors for cogeneration in Nova Scotia, and recognized the need to make additional efforts to establish an environment in which economic cogeneration projects can be brought forward. The EMGC received information from NSPI regarding 2008, when it will need a low emission source of energy in order to meet reduced emission limits for NO$_x$, rather than to meet load requirements.

NSPI has proposed that, to facilitate the development of economic cogeneration projects, a portion of the projected need for low emission energy be reserved, and accelerated.

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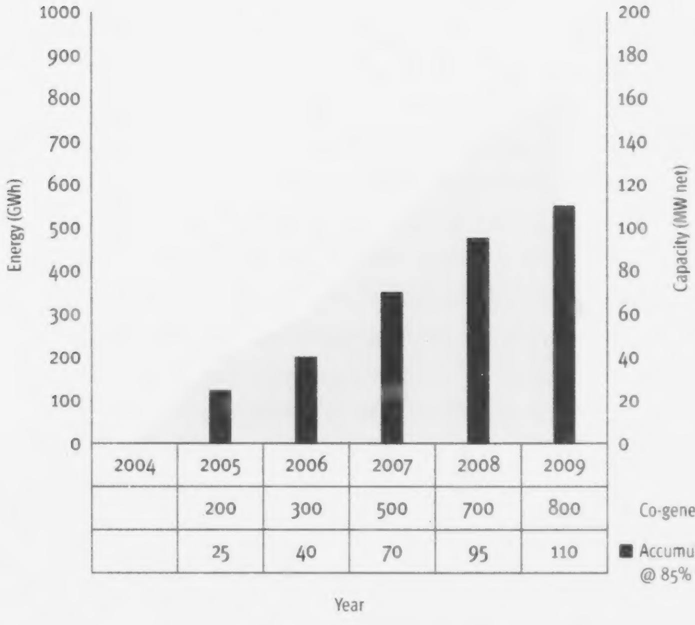
[22] Nova Scotia's Energy Strategy, volume 2, part 3, ("Electricity"), p. 16.

It provided the chart set out below hat operates from the base assumptions underlying projected energy needs in 2008/9, and the lowest cost solution presently identified by NSPI. The area "below the line" indicates where potential system benefits arise from the addition of low emission energy. The area above the line shows generation need, which represents additional cost, in that the capacity is not needed by the system and could result in stranded costs (discussed below in Section II).

NSPI proposed that for all projects that fall below the line it would pay to the cogenerator, on a take or pay basis, its estimated avoided cost of new generation, representing the value to NSPI and its ratepayers of the deferred expenditure. In addition, NSPI proposed that all cogeneration projects that fall below the line (a staged total of 800 GWh over 5 years) would have access to transmission level customers (comprising approximately 24% of the electricity market). Transmission level customers generally have the metering capacity necessary to facilitate a competitive marketplace, and as well, little additional administrative cost is incurred. Moving beyond transmission level will necessarily involve these additional considerations.

Following these initiatives, coupled with the interest of some Committee members, a series of meetings was organised with interested parties to deal with cogeneration issues. This group made some recommendations to the EMGC, particularly with respect to the definition of cogeneration.

COGENERATION OPPORTUNITY



Year	2004	2005	2006	2007	2008	2009
Co-generation Energy Opportunity (GWh)		200	300	500	700	800
■ Accumulative Co-Generation Capacity @ 85% CF (MW net)		25	40	70	95	110

Assumptions:

i) Future energy supply shortfall is based on existing NSPI generation fleet production to achieve air emission compliances as prescribed in NS Energy Policy

ii) Forward natural gas pricing is based on PIRA forecasts

iii) Air emissions compliance options include:

- Fuel switching
- Energy purchases
- Incorporate bw emission technologies

iv) NSPI low cost solution is based on a 370 MW CCGT at 52% cycle efficiency

8.3 DEFINITION OF COGENERATION

A definition of cogeneration is essential if an operational distinction is to be drawn between it and other forms of on-site or independent generation. Given the EMGC need to promote cogeneration a clear definition is necessary; potential program participants need to know if what they propose will qualify for whatever special treatment is afforded cogeneration. Some of the issues that could be addressed in that definition include levels of efficiency, amount of heat utilization, fuel sources, technology, and size.

Presently, a definition does exist which is currently in use for some public policy purposes. The federal income tax code contains a special category, Class 43.1, to encompass efficient or environmentally preferred modes of electricity generation. Facilities that qualify for Class 43.1 status are permitted to depreciate their taxable assets at an accelerated rate.

Generators eligible for Class 43.1 status must use fossil fuel, wood waste, municipal waste, landfill gas or digester gas to generate electricity or electricity and heat. The rate of heat production, attributable to the fossil fuel component, used to generate the electricity can be no more than 6000 BTU per kWh, which is stringent enough standard that only cogeneration would be likely to attain it.[23]

The EMGC considered accepting the Class 43.1 definition, with the condition that the application should include the simultaneous production of electricity and heat or mechanical energy.[24] The definition would only affect the treatment of facilities under Nova Scotia policies. This definition does not have the same impact on tradability, as the definition of electricity from renewables, where facilities may have to meet a national definition in order to be eligible to trade their characteristics.

The cogeneration group also discussed definitions. It was reluctant to adopt the Class 43.1 definition, feeling that it could be too restrictive. Instead, it leaned toward a separate definition that specified a computational formula as well as efficiency and fuel criteria. The cogeneration group also emphasized the role that cogeneration could play in assisting the development of natural gas transmission infrastructure in Nova Scotia, and expressed concern that a definition which set an efficiency threshold at too high a level would deter otherwise economic projects from moving forward. The resulting recommendation is intended to strike a balance.

Recommendation 62

The EMGC recommends that, for public policy purposes in Nova Scotia, facility would be defined as a cogeneration facility if:

- *The facility qualifiesfor treatment under Class 43.1 of the Income Tax Act and produces electricity and usable heat; or*

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[23] The heat rate is raised to 6700 BTU per kWh for an installation on a gas transmission line and using natural gas and waste heat from the compressors, if there is no nearby potential steam host.

[24] The inclusion of applications producing mechanical energy is intended not to rule out pipeline compressor stations, which could produce electricity from waste heat from the compressors.

- *The facility*
    - *contains a process that*
    - *uses heat derived from combustion for the purpose of generation of electricity and other efficient uses of the mechanical or thermal energy, such as process heating, district energy systems, heat absorption chillers, space heating, etc; and*
    - *has an overall thermodynamic efficiency of 57% as calculated by the formula below, and*
    - *dedicates a minimum of 15% and maximum of 70% of its system energy output to the generation of electricity; and*
    - *will anchor a natural gas transmission line to an area or region of the Province of Nova Scotia not then served by gas transportation infrastructure*

The formula for cogeneration efficiency is:

$$\text{Efficiency} = \frac{\text{net electricity output (BTUS)} + \text{useable heat output (BTUS)} \times 100}{\text{low heat value of input fuel (BTUS)}}$$

8.4 POLICIES TO PROMOTE COGENERATION

Potential policies for cogeneration fall into three categories: A) policies that directly increase the financial returns from the project, e.g., access to accelerated depreciation; B) policies that remove barriers to cogeneration; and C) policies that give cogeneration specific incentives to help it overcome existing barriers.

The EMGC did not discuss policies to increase returns to cogeneration, and of the barriers that were identified, it felt that they could be best addressed in relation to market access.

8.5 RECOMMENDATIONS TO ENHANCE MARKET ACCESS

Cogeneration facilities need access to markets for their surplus power. The price they get for that power can greatly impact the facility's economic viability, and therefore it can influence the decision as to whether or not it should be built. The *Energy Strategy* suggests that cogenerators will have the opportunity to sell excess electricity to wholesale and export customers, in addition to NSPI. It was suggested to the EMGC by some stakeholders that access to additional market opportunities would address that success factor. Therefore, in order to improve the economics of cogeneration projects, an important priority must be to include improved market access for surplus power.

Conditions of market access can depend on the size and location of the cogenerator. Facilities over 15 MW are too large to be tied into a distribution system and so must be included directly on the transmission grid. Smaller facilities could be connected to either the transmission or the distribution systems. Since there is wide variation in the electrical strength and capability of the distribution system across Nova Scotia, the impact of any proposed generator must be assessed, and system upgrades applied at the cost of the generator.

Discussions regarding the possible breadth of market access for cogenerators ranged from all customers in Nova Scotia to only large industrial users directly connected to the transmission grid, that is, in the latter case excluding residential and commercial customers.

Cogenerators connected at the transmission level already have appropriate connection agreements with NSPI. They are currently in the position to readily sell power to any customers, as well as those connected to the transmission grid. Permitting them to sell to grid-connected customers will not create the need for much additional market infrastructure, and consequently, the EMGC recommended that they be able to do so.

Recommendation 63

The EMGC recommends that electricity generated by all cogeneration facilities in Nova Scotia connected to the transmission grid can be sold under bilateral contracts to all retail customers connected to the transmission grid.

Some concerns were expressed that, as a result of this recommendation, some customers could take alternative generation supply and avoid paying the fixed cost of the existing system. In effect, such customers could be creating stranded costs, which would then have to be borne by other customers. These concerns will be addressed in Section 10 with policies that deal specifically with stranded costs.

The EMGC had extensive discussions about further extending the cogenerator's market access. However, any extension would necessarily mean allowing competitive access to distribution customers. Allowing even financial contract access to this group could require a heavy investment in infrastructure, such as new computer capacity and billing systems.

The Committee has already recommended full retail access, using financial contracts, for sellers of green energy. By extension, some members of the Committee wanted to allow such access for sellers of power derived from cogeneration. Other Committee members felt that such access would not be effective, because consumers would be less likely to understand the benefits that accrue from cogeneration, including environmental, relative to green energy.

Whatever the level of market access, the EMGC wished to avoid unnecessary investments in the infrastructure that would be needed to extend competition to distribution customers.

The following recommendations embody these concerns.

Recommendation 64

The EMGC recommends that any seller offering electricity from cogeneration, using facilities constructed in Nova Scotia after 2001, be able to sell directly to all electricity customers, other than the domestic and small general classes.

Recommendation 65

The EMGC recommends that producers of electricity from cogeneration resources sell to electricity customers in Nova Scotia on the basis of physical or financial contracts, as contracting parties can and choose to do so.

In addition to electricity customers, generators can also sell to utilities. The possible buyers include NSPI's distribution function, NSPI's wholesale supply function, and distribution utilities. Cogenerators connected at the distribution level (referred to as "embedded" generators, because they are contained directly in the distribution system) could sell to their host utility, or through their utility to NSPI, or through their utility to any customer.

If the sale is to a customer connected at the transmission level, the cost of power from NSPI is easily identified and the financial contract executed by crediting the buyer with the cost of that power.

If the sale is to a customer connected at the distribution level, the transaction is more complicated, because the cost and value of electricity vary over time and the customer is not likely to have metering that will record its hourly use. Under transmission unbundling, the buyer may have an identified price for generation, but it would be an average. To give the buyer proper credit against its total bill for power bought from the cogenerator, the distributor will have to know, or assume, when the buyer actually used the power. Further, because the distribution customer is not a transmission customer, it may not have a price identified for generation alone, but only a bundled price that includes the transmission services bought on its behalf by its distribution utility.

These considerations are important because the key to the success of sales from cogeneration will be the ability to price properly both the sale of the power to NSPI and the purchase under the financial contract by the buyer. Setting up systems to approximate these prices reasonably may be costly.

Pricing of the sales to NSPI will be contained in a PPA between the cogenerator and NSPI. That pricing should properly reflect the value to NSPI of the power bought, because it can be expected that the generator will have appropriate metering.

The EMGC approved the following recommendations to implement these ideas.

Recommendation 66

The EMGC recommends that NSPI offer to buy power from cogenerators under a PPA at a rate that will represent NSPI's avoided cost for new generation and associated transmission, subject to UARB approval.

The EMGC wanted to ensure that this price was arrived at through an open process, and that potential cogenerators would know the terms of the PPA. The following recommendation says that the PPA should be available to all in advance, and that it should be developed in a consultative process.

Recommendation 67

The EMGC recommends that NSPI develop a pro forma PPA, in consultation with stakeholders.

Embedded generators have a somewhat different position from those connected to the transmission grid. Embedded generators can sell directly to their host utility or to customers in the same distribution system. To sell to any other customers, they have to use the infrastructure of their host to move power to the grid, then use the transmission system to transfer the power to their customer.

The EMGC discussed issues associated with giving embedded cogenerators the ability to sell to other customers within the same distribution system. It noted that some potential cogeneration developers might have affiliates or co-sponsors. For example, a hospital group could have several facilities within the same distribution territory and wish to locate cogeneration at one of them, while sending the surplus power to the other. Without the ability to access other customers within the same distribution utility, this would be difficult. However, the EMGC decided that such transactions could become quite complex.

The simplest way for embedded cogenerators to balance off power surpluses or shortfalls would be through an agreement with their distribution utility. The utility has a larger and more diverse load, and should be able to accommodate the cogenerator's needs. Letting the cogenerator sell to the host distribution utility at its avoided cost will provide an outlet for any unused or uncontracted energy at a price that reflects its value. The following recommendation gives embedded cogeneration that right.

Recommendation 68

The EMGC recommends that distribution utilities with cogeneration facilities located within their systems must offer to buy power from the cogeneration facilities at their avoided cost.

8.6 RECOMMENDATIONS TO ADDRESS BARRIERS

For cogenerators connected to the transmission system, as with any independent generation, non- discriminatory access to the transmission system is the key to the ability to sell. With the following recommendation, the EMGC wanted to ensure that such cogenerators do have non-discriminatory access.

Recommendation 69

The EMGC recommends that the owners of all cogeneration facilities connected to the transmission grid be provided access to the transmission system under the same terms as all other generators for both transmission and ancillary services.

As for other self-generators, the cost of backup supply and other services from the grid can be important to the financial viability of cogenerators. The EMGC has already recommended that self- generators pay transmission charges based on their monthly net non-coincident peak demand. Applying this same charge determinant to cogenerators would give them the same terms as other self- generators. In months when they act entirely as generators, or meet only their own load, cogenerators would not pay any transmission charges. In months when they draw from the grid, even for a portion of the month, they would pay some charges.

With this charge determinant, the cogenerators pay for backup service (reserves) only in months when they actually draw power from the grid.

The EMGC recommended that cogenerators have the same charge determinants for transmission and ancillary services as other self-generators.

Recommendation 70

The EMGC recommends that the transmission charge determinants for new cogeneration self-generators be their monthly net non-coincident peak.

One other barrier that the EMGC wanted to address is the fact that, under current Nova Scotia regulations, a cogenerator selling steam to any entity other than itself is classified as a utility, bringing it under regulation by the UARB. Such regulation could be onerous for cogenerators which are simply selling steam or heat "over the fence"; that is, to provide heat to users located on adjacent or nearby properties, or when the cogeneration units are not owned by the steam host. The purpose of the utility definition is presumably to prevent steam sellers, such as a district heating system, from exploiting the monopoly position created once the customers have installed heating systems relying on the steam purchases.

Generally, industrial steam customers already have facilities to meet their steam needs and can switch back to them if the steam provider raises its price excessively. For district heating systems, the concern may be more relevant, since residential customers are not likely to have redundant heating systems. To balance these interests, the EMGC adopted the following recommendation.

Recommendation 71

The EMGC recommends that the UARB develop regulations relating to the sale of heat from cogeneration facilities that:

- *Protect the interests of the users of the heat, while*
- *Entailing reasonable administrative responsibilities for the cogenerator.*

9.0 Standard Service and Heritage Pool

9.1 DEFINITION OF STANDARD SERVICE

A major part of the of the Nova Scotia electricity market will remain closed to competition, even after adoption of the changes envisioned in the *Strategy* and the recommendations offered by the EMGC. NSPI will continue to supply electricity to this market. Since customers are not eligible to choose alternate electricity suppliers, and do not receive any direct benefit from electricity restructuring, they should not be biased against simply because competition is introduced to others.

A mechanism to avoid bias is by offering regulated standard supply service to contestable customers. Standard supply service, or standard service, is the service offered and provided to consumers who do not, or cannot, choose alternate suppliers. Most customers in Nova Scotia will not be able to choose alternate suppliers, at least under the restructuring as currently recommended. Standard service will therefore be the dominant form of supply in Nova Scotia. It will be under regulated prices and terms. The conditions defining the provision of this service can determine the ultimate competitiveness of Nova Scotia's wholesale and retail electricity markets. They can affect the amount of competitive take-up in the eligible market, and can also influence it once it becomes more competitive.

The standard service offer is the one that customers who do have choice will use to compare prices. It must therefore have prices separately identified for the competitive and non-competitive portions of a consumer's bill. The *Energy Strategy* stated, "NSPI will be required to separate accounting for its generation, transmission, and distribution divisions, including ancillary services".[25] Accounting separation will "break out" individual pricing components in the standard service provision of electricity, thereby allowing consumers to identify costs associated with that portion of their bill that is competitive.

The EMGC expects that, since NSPI is a vertically integrated utility with an obligation to meet Nova Scotia's electricity needs, the UARB will continue to regulate NSPI's entire rate structure. In return it can expect to receive its allowed rate of return on the assets required to meet those needs.

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[25] Nova Scotia's *Energy Strategy*, volume 2, part 3, ("Electricity"), p. 15.

9.2 IDENTITY OF STANDARD SERVICE SUPPLIER

NSPI will be the source of electricity required for the standard supply, with the responsibility to service consumers possibly falling on the generation or distribution functions of NSPI, or perhaps on some other organization or agency that could purchase supply from NSPI and subsequently forward it to consumers. Considering that NSPI is currently the principal supplier of electricity to customers in Nova Scotia, the EMGC did not see a need for any other organization to fill that role. The two most appropriate entities within NSPI are the generation and distribution functions, since the transmission provider, as a neutral entity mandated to ensure equal market access, should not assume the role of electricity supplier.

The distribution function of NSPI services distribution customers and does not deal with the municipal utilities. Giving NSPI the responsibility for standard supply would mean that one group of distribution utilities (the municipals) would rely for its electricity supply on another distribution utility (NSPI Distribution), which the EMGC did not think would be appropriate. Therefore, the responsibility for electricity supply, which is essentially a generation activity, should be with the generation function within the unbundled NSPI.

The following recommendation assigns a cost-based standard supply obligation to the NSPI generation function.

Recommendation 72

The EMGC recommends that the generation function of NSPI offer a cost- based standard generation service to all generation customers. Generation customers include all distribution utilities and all customers eligible to choose competitive generation supply.

9.3 DEFINING HERITAGE ASSETS

Heritage assets are those assets that the present customers have already paid for. As a competitive market opens, assets existing at that time may be able to produce electricity more cheaply than new facilities. The right to receive lower-cost supply is said to belong to existing customers, because they paid for the assets under the existing regulated rates. In this regard, the *Energy Strategy* stated:

> *An important objective for any restructuring of Nova Scotia's electricity industry ... is the protection of the current electricity price advantage experienced by consumers and businesses. The [EMGC] will define Nova Scotia's "heritage" electricity assets to ensure protection of our competitive advantage in electricity rates.*[26]

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[26] Nova Scotia's Energy Strategy, volume 2, part 3, ("Electricity"), p. 19.

To be specific, heritage assets in Nova Scotia would be defined as the existing electricity supply from facilities owned or contracted by NSPI. A distinction could be made between such assets and those acquired under the process for new capacity. The newer assets are likely to have higher costs than the existing ones, because of their higher capital costs. Supply from the heritage assets could be designated as such so as to benefit existing customers. As these assets are replaced, total heritage supply would gradually decline.

The EMGC discussed this issue, and concluded that the structure of the proposed electricity market in Nova Scotia makes the definition of heritage assets unnecessary. NSPI has an indefinite obligation to serve load in Nova Scotia. Any new supply it acquires will be at costs based on a market process, because the cost will come from a competitive bidding process. But the customer will continue to be obligated to pay for that supply through its overall generation charges. For the customer, then, no visible difference exists between the supply coming from either heritage or new assets. The customer continues to pay NSPI a blended price based on the rate base value of all the NSPI assets then in service.

Further, the definition of heritage assets could require some expenditure. The assets would need to be identified, and some agreement would be required between their owners (more than likely the generation function of NSPI) and the buyers of the electricity from those assets (probably the distribution function of NSPI). In the absence of a generally acknowledged concept of heritage assets, such agreements would not be needed. Given these considerations, the EMGC determined that there is no need at this time to identify either heritage assets or heritage supply in the Nova Scotia electricity market.

9.4 DEFINING AND PRICING STANDARD SUPPLY

The EMGC recognizes that proper pricing for the standard supply is central to competition. That price will be the benchmark that any competitive supplier must beat. Sellers of power derived from more environmentally desirable resources, such as green energy, may be able to find customers willing to pay more than the standard supply price, but that price would remain as the point of departure. Sellers of power produced through cogeneration or from green energy may need to beat the standard supply price in order to win large commercial and industrial customers.

In addition to the separately identified generation price, customers will need separately identified prices for other services as well. These include, at a minimum, transmission and ancillary services charges. The latter items are usually delivered along with transmission. The following recommendations state that all customers in Nova Scotia should have separate charges for generation and transmission.

Recommendation 73

The EMGC recommends that generation charges be unbundled for all customers.

Recommendation 74

The EMGC recommends that transmission tariffs be unbundled for all transmission customers.

9.5 LEAVING AND RETURNING TO STANDARD SUPPLY SERVICE

The standard supply service, as noted above, will continue NSPI's obligation to serve customers in Nova Scotia. In a competitive market, some customers could choose to take supply from other generators. Making that choice raises the issue of whether NSPI would then continue to have the same obligation to serve those customers, as it does with customers who never changed their suppliers.

Because of its obligation to serve, NSPI must maintain reserve capacity (along with other resources, including interruptible load) above its forecasted peak load, in order to deal with expected needs, like scheduled generation outages, plus unexpected needs, like generation breakdowns or unexpected load growth. All customers pay for this reserve supply through the regulated tariff, because its cost is included in NSPI's rate base. But a customer who elects to buy generation from another supplier is no longer required to pay for reserve capacity.[27] Should that customer be permitted to return to standard supply whenever it decides standard supply to be more advantageous?

If a significant amounts of NSPI's load transfer to competitive suppliers, it would be costly to maintain the capacity to serve that load, in anticipation of some vague possibility of eventual return to standard supply. Such costs would be borne entirely by customers who take standard supply, while allowing the customer who chose otherwise to receive the benefit of reserves without the responsibility of paying for them. Also, if NSPI does not maintain sufficient reserves, customers might not be able to obtain supply if a competitive supplier cannot deliver (through physical or financial failures of the company, for example).

One possible solution could be to allow the customer to return to standard supply, but only on negotiated terms. NSPI would still carry an obligation to supply the customer, but not necessarily on the same terms that existed, prior to its departure. Price negotiations could reflect the supply and demand conditions extant at the time of the customer's return. This would eliminate the possibility that a customer who chooses a competitive supplier would be without electricity supply in the event of a default, thereby reducing the disincentive for any customer to leave.

Another issue relevant to a possible return to standard service is the terms to be considered when planning to leave it. A customer taking competitive supply will no longer be

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[27] The customer still pays for operating reserves through the ancillary services charges administered with the transmission tariff.

responsible for its share of the fixed costs of the system, which was built in part to meet that customer's needs. Leaving the system could create stranded costs, which might make the departing customer responsible for some payment to avoid cost shifting. A customer making such a payment could then be thought of as having paid for a portion of the reserve capacity and could then be entitled to supply upon returning to the system. These issues, regarding departure from the system, are discussed more fully below.

The EMGC noted the similarities of a customer leaving standard supply and a customer currently taking interruptible power under an NSPI interruptible rate. A customer in the latter case must give five years notice to convert their interruptible contracts to firm contracts, in order to allow NSPI to arrange for the new firm supply. This analogy would imply that returning customers could come back, but not necessarily on the same terms as when they left.

To avoid the possibility of a customer being left without supply, the EMGC felt that the standard service provider should have an obligation to supply any contestable customer that has left standard supply and chooses to return.

The EMGC stated principles, although not in the form of a recommendation, for the provision of this service:

- The pricing for this service should prevent cost shifting between existing standard supply customers and returning customers;
- The price for this service should be based on the standard service supplier's cost; and
- The standard service supplier's pricing should be subject to regulatory review.

9.6 MITIGATING MARKET POWER

Market power can be defined as the ability of a market participant to raise a price and maintain it long enough to increase profits. Firms with high market shares often have market power. The ability of new competitors to enter the market and compete away the excess profits by offering goods at lower prices checks their market power. In markets where entry is easy, firms find it difficult to exercise effective market power.

NSPI dominates the Nova Scotia electricity market, and so it could potentially exercise market power, which is one of the reasons that it is subject to price regulation. Price regulation prevents it from raising its prices arbitrarily in order to increase profits. When the market is eventually restructured, NSPI will continue to have regulated prices. Although it cannot arbitrarily raise prices, NSPI could exert control on the market by raising barriers to the entry of new competitors. This has indeed been the case in other electricity markets; potential new entrants have reported that the incumbent utility has erected barriers to entry to protect its market position.

The EMGC discussed several measures to mitigate NSPI's ability to create such barriers. Some have been embodied in recommendations elsewhere in this report, as for example, with respect to the terms of the standard supply. In addition, the conditions for the provision of backup supply or for the sale and purchase of uncontracted power could act as barriers to entry.

Almost all generators need some backup supply. If they are self-generators, they probably need to be able to keep their processes going even if their own generation becomes unavailable through an unplanned outage. If they are providing power to customers under a bilateral contract, they need backup so their customer is not left without power in the event of an unplanned outage. NSPI is likely to have an effective monopoly on the provision of backup supply to such generators. Therefore, the EMGC recommended that it provide such supply at a cost-based, regulated rate. This protects NSPI from having to provide backup at prices below cost, and it protects the independent generators from potentially having to pay prices well above the cost of provision of the specific service.

Recommendation 75

The EMGC recommends that NSPI offer backup supply service to competitive generators, at a price that is cost-based and regulated by the UARB.

Competitive generators will also need support for purchase and sale of small quantities of energy. The EMGC earlier dealt with the conditions for energy imbalances, which arise in the course of operations. IPPs (and their customers) will from time to time have excess energy available for sale, or will need to purchase additional energy to fill gaps. Lack of a mechanism for selling or buying such excess energy could put competitive entrants at a significant disadvantage; it would force them always to match generation only to contracted load, which may at times be difficult.

To help in such problems, some jurisdictions use a top up and spill arrangement. Under that plan,the incumbent utility offers to buy excess energy from competitive generators ("spill") or sell excess energy to generators or their customers ("top up") at a price that is set in advance and approved by the regulator. This service allows IPPs to know what price they and their customers will pay for uncontracted energy. By reducing uncertainty for these market participants, it can reduce barriers to entry.

The EMGC recommended that NSPI offer a top up and spill system.

Recommendation 76

The EMGC recommends that NSPI create a top up and spill system for cogenerators and competitive entrants, under which it buys or sells uncontracted power at a cost- based rate, as approved by the UARB.

10.0 Stranded Costs and Exit Fees

10.1 SOURCES AND DEFINITION OF STRANDED COSTS

As markets are opened to introduce competition and customer choice, formerly regulated monopoly utilities may find that some of their embedded costs cannot be recovered. Costs incurred by utilities in connection with the provision of regulated monopoly service are stranded when they cannot be recovered in a competitive marketplace. Common sources of stranded costs are large capital investments in uneconomic plants and high-priced power purchase or fuel supply contracts.

The rationale for allowing the recovery of these stranded costs from electricity consumers has to do with the regulatory background for restructuring. Utilities were traditionally allowed to collect revenues equal to their prudently incurred costs, including a return on their capital. In the transition to a competitive market, utilities should be able to recover the prudent costs of uneconomic assets and obligations that were incurred under a different set of circumstances.

Stranded costs typically arise when a customer switches to a competitive supplier and so no longer pays the regulated utility for its historical fixed costs. The recovery of legitimate stranded costs is necessary to prevent cost shifting among customer classes and as a means of treating investors fairly.

The issue of stranded costs raises a number of questions. These include the exact definition of stranded costs, the calculation methodology used to determine the magnitude of these costs, methods to mitigate these costs, the allocation of remaining costs among taxpayers and ratepayers, and cost- recovery mechanisms to be used (e.g., exit fees).

In general, stranded costs can be defined as the difference between the market value and the book value of a utility's assets. Stranded costs should not include losses or gains associated with normal business conditions. For example, if electricity sales, decline due to an economic downturn then the resulting reduced utilization of existing assets does not qualify as a stranded cost. In general, costs can become stranded only when consumers take deliberate actions that were not allowed under the regulatory regime in place at the time the costs were incurred.

10.2 APPROACHES FOR STRANDED COSTS

Stranded costs can be handled in three ways:

- Stranded costs are not paid, and the utility is left with reduced payouts;
- Stranded costs are paid by all customers; or
- Stranded costs are paid by the customers identified as causing them.

Some jurisdictions in the United States have failed to pay their utilities all of their stranded costs even though all jurisdictions recognize the fact of stranded costs and the obligation to pay them. In Nova Scotia, avoiding the payment of stranded costs would be inconsistent with the historical treatment of NSPI.

The second approach, that of spreading costs to all customers, usually is applied in jurisdictions where pricing is set by a dynamic market. Stranded costs then arise from the difference between the valuation of the asset with a market-based price and the rate base regulation value of the asset. Stranded costs cannot be recovered simply from the customers who caused them, because they cannot be identified.

The last approach can be used when only some customers are eligible to choose alternative supply, which is the case in Nova Scotia. Specific customer actions as to electricity supply will create stranded costs if the utility is unable to resell the capacity to another customer at prices at least as high as those paid by the departing customer. (If the utility can sell the released power for more than the departing customer was paying, the departure creates a stranded benefit.) In general, where specific customers can be identified as causing stranded costs, considerations of fairness suggest that they should pay those costs.

10.3 IDENTIFYING STRANDED COSTS

The question of whether Nova Scotia will experience generation-related stranded costs or stranded benefits hinges on the relationship between the standard service price, NSPI's incremental cost of production, and the market price NSPI can get for selling the power to other customers, including export customers.[28] These relationships are illustrated in the figure on the next page. Stranded costs would occur if the standard service price was greater than both the price from other customers and NSPI's incremental cost of production. Stranded benefits could occur in two situations. If the market price is greater than the standard service price and released power can be exported, a stranded benefit equal to the difference between the export price and the standard service price will result. A stranded benefit will also result as customers reduce their load on NSPI's system if the standard service price is less than NSPI's incremental cost of production. In this

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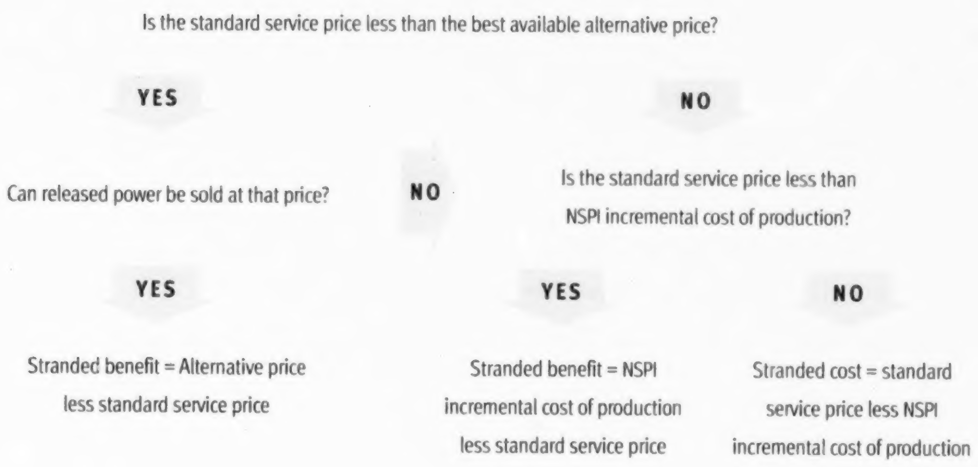
[28] This assumes that the departing customer was receiving standard supply service.

case, a reduced load will contribute to a reduced loss for NSPI.

In Nova Scotia, stranded benefits are unlikely to arise as a result of released power being sold at the best alternative price. Higher prices would likely come from exports to the United States, and transmission access to the United States from Nova Scotia is limited.

STRANDED COST DETERMINATION


Is the standard service price less than the best available alternative price?
YES
NO
Can released power be sold at that price?
NO
Is the standard service price less than NSPI incremental cost of production?
YES
YES
NO
Stranded benefit = Alternative price less standard service price
Stranded benefit = NSPI incremental cost of production less standard service price
Stranded cost = standard service price less NSPI incremental cost of production

10.4 CALCULATING STRANDED COSTS

Nova Scotia has a relatively small number of large industrial customers connected to the transmission system. Were those customers to leave the standard supply service, it would be relatively easy to identify the consequent changes in the utility's costs and revenues. It should be relatively easy to compute the costs stranded by any particular customer's electricity supply action. The EMGC agreed that the customer causing stranded costs should be responsible for paying them. The form of payment is an exit fee; the customer taking competitive supply pays for any stranded costs created when it leaves standard supply.

The Committee also considered what kinds of customer actions might be considered potentially to give rise to stranded costs. Customers can reduce load for a number of reasons, many of which might not create stranded costs. For example, they could reduce their level of activity or they could increase their level of efficiency. The EMGC agreed that only a direct action to reduce load by buying electricity from an alternate supplier would create stranded costs. The size of the stranded cost would be based on the amount of load the customer was taking at the time of its exit.

Recommendation 77

The EMGC recommends that a customer be assumed to create the possibility of stranded costs only when it takes a deliberate action to reduce its load through the procurement of generation supply from an alternative source or the development of a new self- generation project, unless such action does not raise the total supply above the line in the cogeneration opportunity graph shown in section 8.2.

The EMGC agreed that the government in making regulation to enact *Recommendation 77* may choose to exempt municipal utilities with respect to self generation.

Recommendation 78

The EMGC recommends that stranded cost recovery be based on the load of the exiting customer at the time of notification of exit.

The EMGC discussed the mode of calculation of stranded costs. It concluded that the stranded costs are the reduction in value of the assets that would have served the load.

Recommendation 79

The EMGC recommends that stranded costs be defined as the amount of the reduction below book value of generation or transmission assets caused by the exit of a customer.

Recommendation 80

The EMGC recommends that the reduced value be calculated as the difference in estimated net present value of the stranded assets.

The EMGC recognized that the stranded cost could affect all of the NSPI assets, including transmission, used to service the needs of the exiting customer.

Recommendation 81

The EMGC recommends that stranded cost recovery be based on costs of all resources to meet NSPI supply obligations to the exiting customer. Such costs would include generation and transmission costs.

11.0 Energy Efficiency

The *Energy Strategy* did not assign the EMGC a role in promoting energy efficiency programs. It declared "government will encourage NSPI and the UARB to develop creative Demand Side Management (DSM) and Systems Benefit Charge (SBC) programs to improve electricity efficiency and reduce overall consumption".[29] The *Energy Strategy's* treatment of energy efficiency focused primarily on several programs, not specifically aimed at the electricity industry, such as government energy use, appliance and building codes and standards.

The EMGC considered six possible actions, which are not necessarily mutually exclusive, regarding the subject of energy efficiency:

- Offer no recommendation or comment;
- Recommend government support for the principles of DSM and SBC;
- Recommend basic principles for program development.
- Recommend implementing a DSM program.
- Recommend a specific funding mechanism, such as SBC.
- Recommend some specific DSM measures, such as building envelope improvements.

The EMGC recognized, during the course of its discussions regarding promotion of energy efficiency, that programs such as DSM require targeted funding mechanisms, such as SBC. This is especially true if the intent is to fund the program within the electricity industry, where some increase in electricity costs will need to be passed on to consumers. The EMGC was reluctant to increase energy costs, seeing it as a tax on electricity consumers, in order to fund energy efficiency programs to benefit other consumers. Even assuming that the proposed cost increase was confined only to the customer class eligible for energy efficiency programs, the EMGC felt that such a policy would be inappropriate. At the same time, the EMGC recognizes the importance of policies concerned with energy efficiency. Satisfying energy end-use needs by reducing demand reduces fuel consumption and its associated environmental impact. However, changing to more efficient forms of electricity use is only a partial solution.

The EMGC has recommended that NSPI, in planning for future energy requirements, consider the impact that demand side management programs might have on projected future need. The UARB is then asked to ensure that DSM is considered in the preparation of a RFP.

One of the major barriers to the adoption of energy efficient technology is the cost of acquiring relevant information. The *Energy Strategy* proposed government information and

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[29] *Energy Strategy*, Volume 2, Part III, Electricity, Pg. 19

audit programs along with encouragement of energy service companies (ESCOS) as two possible approaches to overcome this barrier. The EMGC also recognizes the importance of information cost barriers and the government's potential role in overcoming them. It also noted that other Canadian governments, provincial as well as federal, already offer information programs to promote energy efficiency. Coordinating with and leveraging such programs could help Nova Scotia achieve greater efficiencies and success with its own programs. The EMGC therefore adopted the following recommendation.

Recommendation 82

The EMGC recommends that the government of Nova Scotia maintain information programs to help users implement energy efficiency. The programs should be coordinated with those of other governments, wherever possible.

After considering other recommendations, including possible principles for the design of energy efficiency programs and support for the *Energy Strategy* suggestion of an SBC or other funding mechanism for DSM programs, the EMGC clearly opposed any program that compelled electricity consumers to pay for energy efficiency programs. It made this position clear in the following recommendation.

Recommendation 83

The EMGC recommends that the province not implement a systems benefits charge or other general funding mechanism which requires electricity customers to pay for energy efficiency programs.

12.0 Regulator Roles and Market Surveillance

12.1 REGULATOR ROLES AND RESPONSIBILITIES

The UARB regulates the electricity market in Nova Scotia, and will continue to do so after the recommended market restructuring. It will retain its existing role and responsibilities, as well as acquiring some additional ones. The EMGC's recommendations and assumptions, if fully implemented, will add to the UARB's scope of regulation, all within its present ambit. For example, the EMGC's first recommendation was that NSPI create and file an open access transmission tariff. The recommendation did not specify where the tariff is to be filed, but the EMGC presumed it to be the UARB. Additional further assumptions included the role of the UARB in regulating NSPI's unbundled rates for generation and distribution, along with cost-based pricing in the standard supply, among others.

12.2 MARKET MONITORING AND SURVEILLANCE

Implementing Nova Scotia's restructured electricity market will require some additional oversight functions. The market will require rules to delineate how market participants relate to the transmission provider. The latter will schedule and dispatch the system, based on received information. If rules are to be effective, they will require an enforcement mechanism. Monitoring behavior and enforcing rules will be new responsibilities for Nova Scotia.

One example of monitoring will involve relating to the behavior of market participants, notably manipulation of the market or the exercise of market power. These responsibilities fall under the umbrella of market surveillance. They are more difficult tasks than simply monitoring for breaches of the market rules, because it requires observation and analysis of market behaviour and results. Restructured electricity markets can assign market monitoring and surveillance to separate entities or group them together into one. Entities most likely to get such responsibilities are the system operator, the existing regulator, or possibly even a new agency, designed and created for that purpose.

The transmission provider must have a role in market monitoring, regardless of whether or not it has formal monitoring responsibility. Since market rules define relationships among market participants, only the transmission provider has sufficient data to determine if a breach of the rules has occurred. At the very least, the transmission provider could provide appropriate market data, with or without prior analysis, to another responsible agency. The EMGC decided that the appropriate agency for market surveillance is the UARB. However, assumption of the market monitoring function might require some duplication of the expertise already held by the transmission provider. Since the transmission provider has both the information and expertise, the EMGC concluded that it should be the responsible agency for market monitoring, and, consequently, it adopted the following recommendation.

Recommendation 84

The EMGC recommends that the transmission provider have the authority and responsibility to monitor for breaches of the market rules, to document such breaches, and to impose such penalties as are allowed under the rules.

If the transmission provider is to have power to impose penalties on market participants, then the latter must have some avenue of appeal. The EMGC decided that the UARB is the proper agency for such appeals.

The EMGC also considered the need for an agency to adjudicate disputes between market participants. These could arise under either the tariff or the market rules. The UARB is clearly responsible for disputes under the tariff, since as the regulator it will approve the tariff. The EMGC considered that the UARB should perform all of these roles.

Recommendation 85

The EMGC recommends that the UARB be given the authority and responsibility to

- *Resolve disputes between parties under the tariff or market rules*
- *Receive and act on appeals from decisions of the transmission provider*
- *Review the performance of the transmission provider.*

Recommendation 86

The EMGC recommends that the UARB be given authority to grant interim or temporary relief, where appropriate, in disputes between parties under the tariff or market rules.

The final role discussed was that of market surveillance. Like market monitoring, market surveillance requires information available only to the transmission provider, in its role as system operator. But surveillance requires a different form of analysis from that used in market monitoring. Surveillance must be sensitive to behavior and results in the market, as well as behavior relative to market rules. The EMGC decided that the UARB is the appropriate agency for market surveillance.

To get the information it needs to perform the market surveillance function, the UARB will need to work closely with the transmission provider. The following recommendation indicates the relative roles of the UARB and the transmission provider.

Recommendation 87

The EMGC recommends that the UARB have the following authorities and responsibilities:

- *Instruct the transmission provider on data to be sent to UARB for market surveillance;*
- *Perform market surveillance for abuses of market power;*
- *Power to initiate investigations and to respond to complaints of the abuse of market power or of abuse of monopoly position in respect of the transmission system;*
- *Oversee the transmission provider in its role as market monitor.*

12.3 RESOURCES FOR THE UARB

Both the *Energy Strategy* and the recommendations coming from the EMGC will expand the role of the UARB. As noted above, the UARB is assumed to continue to be the regulator for a cost-based ratemaking system. That system will be more complex, since it will price generation, transmission and distribution separately.

The UARB also will be assigned several new roles. The *Energy Strategy* assigned it the new role of managing the procurement process for the acquisition of new capacity. EMGC recommendations assign the UARB the role of transmission provider overseer,locus of appeals from decisions of the transmission provider, arbiter of disputes between market participants, market surveillance, and the licensing of retail sellers. All of these responsibilities call for varying levels of expertise and a different analytical approach from that of the regulator charged with setting cost-based prices for a regulated utility.

The EMGC expresses its concern that proper performance of these roles is essential to the functioning of the Nova Scotia electricity market. Therefore, the UARB should be given resources commensurate with the role it is being asked to perform. Electricity restructuring in Nova Scotia is not electricity de- regulation. The regulator has an increased, not a decreased, role, and will need resources in accordance with that role.

12.4 MAKING MARKET OPERATION RULES

The EMGC did not discuss ongoing responsibility for the market rules, which govern the relationship between the transmission provider and the market participants. In other markets, the system operator, or transmission provider, typically has responsibility for maintaining and amending the market rules. It is also responsible for filing and administering the transmission tariff, which also governs the relationship between the transmission provider and the market participants.

However, government often makes the initial set of market rules. The EMGC recommendation assigns that responsibility to the government.

Recommendation 88

The EMGC recommends that rules and procedures to implement the electricity market in Nova Scotia be developed by the Department of Energy, with input from stakeholders as it determines.

12.5 LICENSING RETAIL SELLERS OF ELECTRICITY

Under the EMGC recommendations, sellers of electricity from renewable resources and related products (eg, green tags) can sell directly to all electricity consumers. Sellers of electricity from cogeneration facilities can sell to larger consumers (all but residential and small commercial.)Experience in other jurisdictions warns that marketers of electricity, or related products, to small customers can engage in abusive practices. For example, marketers send representatives door to door, using misleading sales tactics. Since the idea of buying green tags, for example, is a complex one, their sale lends itself to such abusive tactics, more so than the sale of electricity alone.

Sellers can be controlled through a licensing system. License conditions can deter them from abusing customers or using misleading tactics. Penalties for breaching conditions can include fines and loss of license. The licensor could be a specialist in energy, or it could be an existing consumer protection agency. Given the special nature of the product to be marketed, the EMGC adopted a recommendation assigning the licensing responsibility to the UARB.

Recommendation 89

The EMGC recommends that all retail sellers of electricity or related products be licensed by the UARB or the Department of Energy.The licensor will set and enforce standards of conduct, including a system of monitoring the retail sellers.

13.0 Additional Actions for Nova Scotia

All of the EMGC recommendations define future actions, which when taken collectively, spell out a series of steps that should advance the process of electricity restructuring in Nova Scotia. However, the EMGC is aware that its recommendations are fundamentally a framework, which will in many instances rely on subsequent processes for additional augmentation. The remainder of this chapter provides additional commentary germane to those subsequent processes.

13.1 COSTS AND BENEFITS OF INCREASED COMPETITION

EMGC Recommendations 2 and 3 urge the Government of Nova Scotia to undertake a more thorough study of the costs and benefits of electricity competition, and once that study is complete to resume discussions as to the possibility of broader electricity competition. As noted in this report, the EMGC received, from both Navigant Consulting and NSPI, informal estimates of some anticipated transition expenses. The EMGC intended that, with further investigation, some additional information would be drawn from other jurisdictions that had actual experience in increased competition, which could show whether the expected benefits of lower electricity rates and greater consumer choice have indeed materialized.

13.2 LONG TERM PLANNING AND CAPACITY ACQUISITION

The EMGC recommended (Recommendation 7) that NSPI annually create and file (with the UARB) a long-range plan addressing system capacity and adequacy. It also recommended (Recommendation 9) that this plan include both supply- and demand-side measures. Also, in keeping with the *Energy Strategy*, the EMGC recommended (Recommendations 12 and 13) an open solicitation process, overseen by the UARB, to procure any new resources. Several aspects of these recommendations will require further definition.

One issue is the identification of a reference long-term plan. Avoided cost, a key planning variable, would flow from a reference plan. (Avoided cost is the cost against which demand side measures are evaluated, so it is essential to understanding the demand/supply tradeoffs.) The annual plan will have an avoided cost, but it will not be approved as a planning reference. As the UARB and NSPI deal with annual plans in the future, they may wish to develop a reference plan in order to identify an acceptable avoided cost and allow demand side planning and evaluations.

EMGC recommendations as to planning and acquisition identify what NSPI should do, but not the unit within NSPI that should do it. The EMGC did not wish to restrict the company's choices as to the allocation of internal responsibilities. Despite the fact that NSPI will be functionally (but not corporately) unbundled, the EMGC does consider the assignment of these planning functions to be important and expects them to be part of the further development of the planning process.

Another EMGC concern regarding planning and acquisition is the selection of new resources to provide standard supply. Both the EMGC recommendations and the *Energy Strategy* identify NSPI's obligation to respond to any solicitation, in keeping with its obligation to supply. Evaluation of responses will be a complex task. Proposals may include both demand- and supply-side options, with varying technologies, lives and cost characteristics. It is possible that the least-cost choice could contain a mix of elements from several proposals, possibly including various sizes, technologies and elements of demand side management.

The bidding and evaluation process will need to be transparent, if it is to work. Bidders will be reluctant to compete against an incumbent like NSPI unless they can be assured of the fairness of the evaluation process. The EMGC believes that a further process to address these issues could includepresent and futurestakeholder involvement. The latter group of future stakeholders might include potential generation entrants, not yet active in Nova Scotia. This stakeholder process could take place under the auspices of the UARB, which will have responsibility for overseeing the acquisition process.

13.3 RPS DEFINITIONS

EMGC recommendations 40 to 45, 49 and 50 address a mandatory renewables portfolio standard (RPS) that would take effect in 2006, following termination of the current NSPI voluntary renewables initiative. Together, these recommendations set a framework for the RPS but there remains a need forfurther definition of the RPS mechanism, in sufficient detail to implement it.

The issues to be addressed in this future process include:

- The actual electricity base from renewable resources in 2005
- Any NSPI obligation to procure electricity from renewables on behalf of other LSEs
- Adjustment mechanisms, if any, to account for the potential lumpiness of load growth
- Creation and allocation of renewable tags from heritage renewable generators.

The future process should include stakeholders from both supply and demand sides for renewables.

13.4 TRANSMISSION TARIFF DESIGN

NSPI informed the EMGC that it is currently developing an open access transmission tariff, which it will file in due course with the UARB. The EMGC believes that there should be a stakeholder consultation process on several issues, including:

- whether the transmission tariff should include point-to-point service within Nova Scotia; and
- whether load participants will be able to self-supply operating reserve and other ancillary services.

13.5 MARKET RULES

In Recommendation 88 the EMGC urged the Department of Energy to develop the market rules or procedures necessary to implement the Nova Scotia electricity market. The Department would determine the level of stakeholder input.

System operation is a function separable from the provision of transmission service. The system operator is responsible for scheduling the entire system, in response to information provided by the market participants. The relationship between system operator and market participant is governed by the market rules. The EMGC expects that the development of the market rules will involve stakeholder participation.

13.6 TOP UP AND SPILL

In Recommendation 76, the EMGC urges NSPI to offer a cost-based top up and spill service for uncontracted power, while in Recommendation 23, the EMGC recommended that the system operator be required to offer energy imbalance as an ancillary service. These are not mutually exclusive recommendations. Energy imbalances arise, in general, from inadvertent or unexpected deviations in either load or generation, from their scheduled amounts, while the top up and spill service is intended to address known uncontracted energy or load. However, these two services are similar in nature, in that they both deal with relatively small amounts of power in the short term. Implementation of the top up and spill service will require further definition, especiallywith respect to sizes, pricing, and implementation mechanisms. This topic could be added to the discussions with NSPI on the development of the transmission tariff, even though they may not be part of the tariff.

13.7 COGENERATION DEFINITIONS

As noted in Section 8, a group of EMGC members has met with stakeholders interested in cogeneration. They have agreed on the definition of cogeneration contained in this Report. The EMGC believes that outstanding issues regarding cogeneration remain, and that they should continue to be discussed, either with this group or in some other forum.

Outstanding issues include:

- definition of the contracting process for sale of cogeneration to customers;
- creation of a pro forma Power Purchase Agreement under which NSPI will buy power from cogenerators
- pricing and other terms for the distribution utility's offer to embedded cogenerators; and
- a quantification formula for the existing definition.

13.8 SALES TO RETAIL CUSTOMERS

The EMGC recommended (Recommendation 51) that any seller offering electricity from renewable resources in Nova Scotia should be able to sell to any consumer, and that (Recommendation 64) any seller of electricity from cogeneration should be able to sell to all but the smallest customers. These recommendations effectively create limited retail access.

In other jurisdictions, retail access has required costly revisions to billing and other systems. The EMGC does not wish to impose such costs in Nova Scotia. An additional process will be required to define ways for specified sellers to reach customers. As the EMGC suggested (Recommendation 52), a preferred way might beto undertake only financial contracts, which can eliminate the need for significant metering and billing system changes.

Experience in other jurisdictions shows that opening electricity markets to competition for small customers creates a need for consumer protection. Consumers typically need education on the nature of the goods being offered plus some protection from deceptive or misleading sales tactics. The EMGC recommended (Recommendation 89) some consumer protection in the form of licensing by the UARB, accompanied by a standard of conduct for licensed sellers. The development of standards and other forms of consumer protection will require an additional process.

13.9 THE LEGISLATIVE PROCESS

This report contains a number of recommendations that, if accepted by the Government of Nova Scotia, will need to be incorporated into legislation and subsequently proclaimed into law during a sitting of the legislative assembly before they can be fully implemented. Considering that this process requires the drafting ofnew legislation, to be followed by an extensive public review process,prior to submitting it to the legislative assembly, the earliest projected time frame for the completion of this process is currently projected to be the spring of 2004.

13.10 ROLES AND RESPONSIBILITIES OF THE UARB

The recommendations contained in this report, if fully implemented, will create several new roles for the UARB. They include responsibility for standards of conduct and licensing for retail sellers; responsibility for overseeing the process for acquisition of new resources; responsibility for market surveillance; responsibility for monitoring breaches of the market rules; dispute resolution and appeals from decisions of the transmission provider; approving prices for standard supply; and approving a top up and spill service for uncontracted power. These responsibilities will be in addition to its existing responsibility for approving NSPI rates, which will be unbundled. The EMGC believes that these new responsibilities will require expanded resources for the UARB, and that the new resources should add different kinds of expertise from those the UARB currently possesses, given that the forthcoming tasks will be of a different kind.

Appendix A

Terms of Reference
Nova Scotia Electricity Marketplace Governance Committee (EMGC)

Purpose

The Electricity Marketplace Governance Committee (EMGC) will report to the Minister of Energy and recommend the implementation, development, structure, economic considerations, and rules to introduce limited electricity competition in Nova Scotia.

Energy Strategy Electricity Objectives

- To maintain access to secure, reliable, and affordable electricity generated in an environmentally responsible manner.
- To encourage long-term competition.
- To promote the growth of renewable energy sources in Nova Scotia.

Energy Strategy Policy Directions

The energy strategy made some high-level policy decisions regarding the degree of electricity restructuring that will take place in Nova Scotia by 2005, which are highlighted below. The strategy also flagged policy needs for the longer term related to renewable performance standards and possibly increased competition.

- The government will work with Nova Scotia Power Inc. (NSPI) and other industry stakeholders to carefully and gradually open up the electricity marketplace in Nova Scotia.
- As a first step toward opening the markets, the government will create an EMGC, which will seek input from a broad range of stakeholders to develop detailed recommendations regarding the subsequent implementation of the specific electricity restructuring measures announced in the energy strategy.
- Introduce competition within the electricity sector in a staged and measured process beginning with supply to wholesale customers (currently six municipal utilities).
- Authorize open access transmission on NSPI facilities for all generators selling to wholesale customers or export markets.
- Introduce competition for new electricity generation capacity.
- Assist the development of an independent power producer's (IPP) renewable sector by permitting these IPPs sited in Nova Scotia to wheel green power directly to customers, and setting a voluntary target of 2.5% (50 MW) for new renewable generation by IPPs.
- Encourage the development of co-generation.
- Allow net metering for customers with micro-generation units.

EMGC Chairperson

In order to expedite the commencement of work and get the EMGC operational as soon as possible, the chairperson of the EMGC will be appointed by government.

The ideal candidate for this paid position will possess the following qualifications:

- independent expert with no direct connections to any of the major stakeholders in the Nova Scotia's electricity marketplace;
- possess a good understanding of the electricity issues that the EMGC will be required to resolve;
- possess excellent organizational and administrative skills;
- be a diplomatic negotiator;
- be able to work to very demanding time lines;
- possess excellent oral, written, and presentation communication skills;
- be familiar with the key stakeholders in the Nova Scotia electricity marketplace; and
- possess a thorough understanding of the functional operation of government.

The contracted chairperson should be given a one-year appointment, and paid on a per diem basis at a rate and time allocation to be negotiated between the government and the selected candidate.

EMGC Membership

The membership in the EMGC will include a broad range of stakeholders. The committee will be comprised of representation from the following organizations:

- NSPI (1 representative covering its range of business functions – generation, transmission, distribution, customer service);
- municipal utilities (1 representative from organization of municipal electric utilities);
- large customers (1 representative chosen from Canadian Manufacturers and Exporters);
- medium sized customers (1 representative chosen from the Electricity Consumers Alliance of Nova Scotia);
- residential consumers (1 representative from the Consumers Association of Canada);
- independent renewable power producers (1 representative from the Renewable Energy Industries of Nova Scotia);
- small business (1 representative from Canadian Federation of Independent Business).

In addition, the following organizations will be invited to have observer status at the meetings:

- Nova Scotia Department of Energy;
- Nova Scotia Utility and Review Board. (1 observer/representative); Chambers of Commerce (One representative from the Association of Chambers of Commerce).

EMGC members will be compensated for travel expenses incurred to attend EMGC meetings.

EMGC Support Services

The EMGC will have requirements for administrative services and may require occasional staff and consultant services, which will be coordinated through the Energy Department. Some of the issues to be resolved by the EMGC will require the assembly of additional information materials. The EMGC will link with the electricity policy group of the Energy Department and other government officials (for example: environment, business development, municipal affairs, etc.) as required.

Public Input to the EMGC

The EMGC members represent both their own organizations and other stakeholders in their constituency group. EMGC members will consult with these stakeholders in order to bring wider participation to the process. Aside from the input received from its membership, the EMGC must also facilitate input from other interested Nova Scotians. This will be accomplished through the public posting of all EMGC background materials, minutes, decisions, work plans, timetables etc. on a web site and encouraging individuals to submit their views on relevant issues to the EMGC for consideration and public posting on the website.

Deliverables and Time Lines

The EMGC will have one year, commencing April 2002, to make recommendations to the Energy Minister on several complex issues related to wholesale competition, open access transmission, and renewable generation of electricity. The Committee is expected to deliver several interim reports, followed by a final report at the end of December 2002.

The EMGC will be required to publically post meeting minutes, background materials, interim reports outlining its progress on key decisions, and ultimately, its final report outlining its list of specific recommendations to the Energy Minister

Overview of Key Market Design Issues and EMGC Responsibilities

Group 1 – Responsibilities to be reported on initially by December 2002

- Recommendations to ensure that transmission system access is available to all market participants on an equitable basis.
- Establishment of exit fees or other method for handling stranded costs.
- Responsibility for the non-contestable market (standard offer supply).
- Which customers are entitled to standard offer supply?
- The definition of renewable energy for policy purposes.
- How is new capacity added to the Nova Scotia generation system?

Group 2 – Responsibilities to be reported on initially by December 2002

- Design of a system that retains for existing Nova Scotia consumers, the benefits of the low-cost system that they have already paid for, i.e. "heritage assets".

- Recommendations on the promotion of co-generation (definition, transmission access, etc.).
- How will green power marketers get access to end-use customers? Would the access in effect require physical or financial contracts between the marketer and the customer?
- What will the role of NSPI be with respect to green power in the medium and longer term?
- If the contracts are financial, how can the sellers of green power be monitored to ensure that they only sell the green power once?
- If/when a Renewable Portfolio Standard is to be implemented, what is the target capacity and time frame to achieve it? To which market participants does it apply?
- Under what circumstances should net metering be permitted? Encouraged?

Longer term issues to be reported on beyond December 2002 (scope as yet to be finalized)

- Recommendations on creating and maintaining workable competition in the Nova Scotia electricity marketplace (market power issues).
- Recommendations on market surveillance and enforcing adherence to market rules.
- Mechanisms to determine when new investments or competitive supplies create stranded costs.
- Compatibility of the Nova Scotia system with those in the Northeast region (US and other Canadian jurisdictions).
- Issues of reciprocity and the relation to transmission developments in both Canada and the United States.
- Ability of the Nova Scotia electricity market to evolve over time as necessary.

Relationship with the UARB

The EMGC will be making recommendations to the Energy Minister regarding implementation of the energy strategy. The energy strategy sets the high level direction. The EMGC will rely on the experience of its members and extensive consultation to provide much more detail on implementation, in order to achieve overall strategy objectives. These EMGC recommendations will be used by the Energy Minister to implement changes to legislation, regulations and government policy.

The Nova Scotia Utility and Review Board (UARB) regulates Nova Scotia Power Inc., which will remain a regulated utility. The UARB will continue to oversee NSPI, approve rates for NSPI electricity service, approve open access transmission rates, determine the requirement and timing for new generation capacity, approve the structure and fees for customers accessing "green power", etc. The UARB has ultimate authority for implementation and oversight based on the overall rules set by government.

Appendix B

Committee Participants

Canadian Federation of Independent Business
Todd Holman

Canadian Manufacturers and Exporters
Fred Hussey, Principal
Grant Ferguson, Alternate

Consumers Association of Canada
Nickolas Murray

Electricity Consumers Alliance of Nova Scotia
John Woods, Principal
Norman Pierce, Alternate

Municipal Electrical Utilities of Nova Scotia Cooperative
Don Regan, Principal
Tom Wadden, Alternate

Nova Scotia Power Inc.
Christopher Huskilson, Principal
(until 31 December 2002)
Jim Connors, Principal (as of January 1, 2003)
James Taylor, Alternate
Peter Doig, Alternate

Renewable Energy Industries Association of Nova Scotia
Erik Twohig, Principal
Will Apold, Alternate

Nova Scotia Chamber of Commerce
Rick Connors, Observer

Nova Scotia Utility and Review Board
George Smith, Observer

Nova Scotia Department of Energy
Scott McCoombs, Project Manager
Alan Crandlemire

Navigant Consulting Company
Mitchell Rothman, Principal
John Dalton, Alternate

Chairman
Robert Fournier

Appendix C

Summary of Recommendations

MARKET SCOPE

EMGC Recommendations on Market Scope (Sect. 4.1.4)

Recommendation 1
The EMGC recommends that Nova Scotia's initial market opening, to encourage electricity competition, be restricted to wholesale customers, who will then be eligible to purchase electricity from any competitive supplier; and that sellers of electricity from cogeneration, or from renewable resources located in Nova Scotia, be able to sell directly to consumers under certain conditions.

Recommendation 2
The EMGC recommends that the Government of Nova Scotia begin a detailed quantitative analysis of the costs and benefits associated with broader electricity competition in the Province. Such an analysis is necessary for any further stakeholder and/or government consideration to broadening electricity competition.

Recommendation 3
The EMGC recommends that the Government of Nova Scotia resume deliberations regarding the possibility of broader electricity competition when the cost and benefit analysis has been completed.

MARKET MODELS

EMGC Recommendations on a Market Model (Sect. 4.2.4)

Recommendation 4
The EMGC recommends that eligible Nova Scotia buyers should arrange for competitive supply through bilateral contracts with eligible sellers.

Recommendation 5
The EMGC recommends that eligible sellers in the Nova Scotia competitive electricity supply market include generators, cogenerators, importers, and agents, brokers, traders, marketers and aggregators.

PLANNING FOR RELIABILITY

EMGC Recommendations on Planning (Sect. 5.2)

Recommendation 6
The EMGC recommends that, as long as it has an obligation to serve, NSPI be responsible for planning for electricity supply for Nova Scotia.

Recommendation 7
The EMGC recommends that NSPI produce an annual long-range plan, with a horizon of at least 10 years. The plan should address both 18-month and 10-year horizons for the purpose of assessing system capacity and adequacy and for planning to maintain system adequacy.

Recommendation 8
The EMGC recommends that NSPI's annual plans be filed with the UARB, and that the UARB open a period for public comment on the plans.

Recommendation 9
The EMGC recommends that NSPI's annual plans include consideration of demand-side and supply-side measures to meet any projected need.

EMGC Recommendations on the Process for Capacity Acquisition (Sect. 5.3)

Recommendation 10
The EMGC recommends that the UARB oversee any competitive process for NSPI to acquire new resources of demand management or generation facilities.

Recommendation 11
The EMGC recommends that there be timelines established for the UARB in its oversight of the process and its approval for the acquisition of new resources.

Recommendation 12
The EMGC recommends that there be an open solicitation process to acquire or contract for new generation or DSM.

Recommendation 13

The EMGC recommends that the UARB consider emissions impacts and thermal efficiency in its review process for new resources.

Recommendation 14

The EMGC recommends that the Standard of Conduct for NSPI ensure that confidential information obtained by NSPI in its role as transmission provider during an RFP process for new capacity not be shared with employees of NSPI's Generation business unit or its affiliates.

TRANSMISSION ISSUES

Importance of Transmission (Sect. 6.1)

Recommendation 15

The EMGC recommends that NSPI develop and file a transmission tariff.

Recommendation 16

The EMGC recommends that any transmission tariff developed for use in Nova Scotia ensure open and non-discriminatory transmission access for all market participants.

Transmission Tariff Options (Sect. 6.2)

Recommendation 17

The EMGC recommends the development of a transmission tariff for Nova Scotia that should initially include a scheduling and information system that need not be an OASIS.

Recommendation 18

The EMGC recommends that transmission tariffs in Nova Scotia develop towards eventual FERC compatibility.

Recommendation 19

The EMGC recommends that, when an OASIS is required to facilitate the reservation of firm and non-firm transmission, together with the associated functions of publication, scheduling, etc., the transmission provider seek ways to minimize its cost, including purchasing OASIS service from another jurisdiction which supports an OASIS.

Transmission Services Offered (Sect. 6.3)

Recommendation 20

The EMGC recommends that transmission services that are to be offered under the transmission tariff should initially include:

- Network Integration Service for the delivery of both capacity and energy for the supply of load located within the Nova Scotia control area
- Point-to-Point service for the reservation of transmission capacity from a specific point of receipt to a specific point of delivery for transactions involving imports into or exports from Nova Scotia. (Point-to-Point service would be offered on both a firm and non-firm basis).

Recommendation 21

The EMGC recommends that the transmission provider acquire ancillary services from market participants at least cost possible, including by competitive contract processes.

Recommendation 22

The EMGC recommends that the transmission provider offer an energy imbalance service based on costs, as approved by the UARB.

Recommendation 23

The EMGC recommends that the transmission tariff require the system operator to offer each of the following ancillary services:

- scheduling, control and dispatch
- reactive supply and voltage control
- energy imbalance
- regulation and frequency response service
- operating reserve – spinning reserve
- operating reserve – supplemental

Recommendation 24

The EMGC recommends that NSPI should give consideration to simplification in its tariff development, including point to point service and self-supply of ancillary services.

Recommendation 25

The EMGC recommends that NSPI should consult with stakeholders in the consideration of tariff simplification.

Definition of Transmission – Radials (Sect. 6.4.2)

Recommendation 26

The EMGC recommends using the following principles to determine whether the costs of transmission facilities should be included in the transmission tariff:

- The cost of a transmission facility used solely by one party should be assigned or charged to that party.
- The cost of transmission facilities that are not part of the transmission backbone should be directly assigned or charged to those parties that use them. The preferred alternative for realizing this objective is:
  - Costs for radial lines serving generators be assigned to those generators
  - Costs for generation step-up transformers be assigned to those generators
  - Costs for radial lines serving distribution loads be assigned to distribution, the revenue requirement to be recovered uniformly from all distribution level customers, supplied by both NSPI and the municipal utilities.

Charge Determinants (Sect. 6.4.3

Recommendation 27

The EMGC recommends that transmission revenue requirements be allocated based on the average twelve monthly coincident peaks.

Billing Determinants - Net or Gross Peak (6.4.4)

Recommendation 28

The EMGC recommends that the billing determinants to establish transmission charges for network customers be monthly net non-coincident peak demand and that for point-to-point customers it should be reserved capacity (estimated on a net load basis, if necessary.) The charge basis for existing self-generation customers would be hourly net non-coincident peak.

Rates – Location and Voltage (Sect 6.4.5)

Recommendation 29

The EMGC recommends that the transmission tariff rate design be based on a consistent charge regardless of the location of the connecting customer, and that in addition new transmission customers be assessed locational factors relating to transmission losses, which may be negative or positive.

Management of Internal Congestion (Sect 6.5.1)

Recommendation 30

The EMGC recommends that all existing customers share the congestion costs on the existing system.

Recommendation 31

The EMGC recommends that new generators and major loads be required to pay:

- All costs to connect to the transmission network.
- All costs of system upgrades required to mitigate congestion costs that they would otherwise create. Generators who agree to be constrained down if this alleviates the congestion to a level consistent with what previously existed will not be charged for additional congestion costs.
- Any direct transmission system benefits from the investments charged to the generator or load (e.g., reduced losses or reduced congestion costs that are borne by other parties) will be credited to the generator or load.
- Any direct benefits or costs due to the impact of the new generation or load on total system losses will be paid or charged to the new generation or load.
- The generator will be responsible only for the cost of advancing construction facility upgrades if the transmission service provider has previously identified them as required for reliability purposes.

Recommendation 32

The EMGC recommends that existing firm load customers within Nova Scotia be entitled under the open access tariff to firm Network Service,and that they have renewal rights to such service.

Transmission Rights on the Interties (Sect 6.5.2)

Recommendation 33

The EMGC recommends that Nova Scotia maintain a system of import and export transmission rights for electricity and capacity.

System Operator Functions (Sect 6.6)

Recommendation 34

The EMGC recommends that the transmission function within NSPI be given the role and responsibilities of a Transmission Provider, including:

- Create and file an open access transmission tariff
- Provide transmission service under the transmission tariff
- Provide ancillary services under the transmission tariff
- Operate the transmission system in accordance with the transmission tariff
- Be responsible for the safe and reliable operation of the electricity supply system in Nova Scotia
- Schedule transactions on the interconnections between Nova Scotia and neighboring jurisdictions.

Metering Standards (Sect. 6.7)

Recommendation 35

The EMGC recommends that, as metering installations at transmission interfaces with generation, distribution or large customers are replaced or resealed, they are upgraded to or replaced by revenue quality interval meters.

PROMOTING GENERATION FROM RENEWABLES

Definition of Renewables (Sect. 7.2.1)

Recommendation 36

The EMGC recommends that, for all public policy purposes relating to electricity supply, Nova Scotia adopt the EcoLogo® definition of renewable low-impact electricity.

Recommendation 37

The EMGC recommends that the Province of Nova Scotia participate in a process to identify renewable resources of wave and tidal power and other new technologies as renewable low impact electricity under the EcoLogo® definition.

Certification and Monitoring (Sect. 7.2.2)

Recommendation 38
The EMGC recommends that, for all public policy purposes in Nova Scotia, the Nova Scotia government authorize accredited companies or agencies to certify that generation facilities meet the Nova Scotia definition.

Recommendation 39
The EMGC recommends that, for all public policy purposes in Nova Scotia, the Nova Scotia government authorize accredited companies or agencies to monitor that facilities continue to meet the Nova Scotia definition and that sales levels of complying electricity do not exceed production supply levels.

Mandatory Long – Term RPS (Sect. 7.4)

Recommendation 40
The EMGC recommends that the province of Nova Scotia adopt a mandatory RPS to take effect in 2006.

Recommendation 41
The EMGC recommends that electricity from renewable resources have RPS tags that can be created and traded separately from the electricity itself.The RPS tag is a certificate that a quantity of electricity has the attribute of coming from a certified renewable resource.

Recommendation 42
The EMGC recommends that entities responsible for acquiring electricity from renewable sources can acquire RPS tags by contracting directly with a certified generator or by purchase from other tag holders.

Recommendation 43
The EMGC recommends that the province of Nova Scotia require each LSE to obtain RPS tags certifying that the fraction of its electric energy from renewable sources by 2010 is equal to the actual base of renewable electric energy at 2001 plus 5.0%.

Recommendation 44
The EMGC recommends that, to encourage the development of a stable renewable energy sector, and meet the environmental goals established by the RPS, that NSPI be required to annually report to the UARB as to its progress toward meeting its goals and that the UARB have the authority to issue directions to NSPI to ensure that these goals are met.

Recommendation 45

The EMGC recommends that "RPS tags", obtained from certified Nova Scotia renewable generators, carry an expiry date set 18 months from the month of generation, by which time they will have been used by an LSE to meet the RPS requirement, or they will have lapsed.

Recommendation 46.

The EMGC recommends that the province of Nova Scotia recognize the heritage attributes of renewable generation that existed in December 2001.

Recommendation 47

The EMGC recommends that the tags relating to the output of the heritage renewable generators (2001 generation plus NSPI constructed or contracted facilities to 2005), which will be the base electric energy at 2005, be assigned to LSEs as at the RPS implementation date in proportion to their load share.

Recommendation 48

The EMGC recommends that existing renewable generators a) be exempt from any certification requirements by virtue of their heritage position; and b) that LSEs maintain their proportional rights to the tags from heritage generation.

Recommendation 49

The EMGC recommends that heritage facilities be able to create and sell new tags to meet RPS requirements only upon becoming certified as renewable. The new tags would come from either a) incremental increases in production based upon expansion or technology upgrades; or b) the output of a facility that was significantly rebuilt in lieu of facility retirement.

Recommendation 50

The EMGC recommends that new renewable generators within Nova Scotia, on-line after December 2001, be eligible to sell tags to LSEs as the method of meeting the RPS targets.

Green Energy Marketing Program (Sect. 7.5)

Recommendation 51

The EMGC recommends that any seller offering electricity from renewable resources using facilities constructed in Nova Scotia after 2001 be able to sell directly to electricity customers.

Recommendation 52

The EMGC recommends that sellers of electricity from renewable resources sell to electricity customers in Nova Scotia preferably on the basis of financial contracts, although physical contracts are certainly acceptable where the contracting parties can and choose to do so.

Recommendation 53

The EMGC recommends that all electricity distributors in Nova Scotia should discuss access to their billing services in good faith with sellers of green energy, and offer such services on non-discriminatory terms.

Recommendation 54

The EMGC recommends that transmitters and distributors in Nova Scotia adopt connection standards for small-scale generation that properly reflect the size and potential system impact of the facility.

Net Metering (Sect. 7.6)

Recommendation 55

The EMGC recommends that a generator qualifying for net metering be one with a suitable interconnection and operating agreement, using renewable resources for generation.

Recommendation 56

The EMGC recommends that qualifying generators with installed capacity of 100 kW or less, connected to a distribution system, be eligible for net metering programs.

Recommendation 57

The EMGC recommends that no distributor in Nova Scotia be required to accept net metered installations having a total installed capacity of more than 0.5% of its annual peak demand.

Recommendation 58

The EMGC recommends that, subject to approval by the Utility and Review Board, excess energy delivered to the distributor from net metering installations can be carried over to subsequent billing periods, for up to 12 months. At the end of each rolling 12-month period, excess energy credits are set to zero without compensation to the generator.

Recommendation 59

The EMGC recommends that NSPI expeditiously finalize the connection standard(s) currently under development for small generators connected to a distribution system.

Recommendation 60

The EMGC recommends that distribution utilities in Nova Scotia be required to adopt technical standards for net metering installations that properly reflect the size of the installation and its potential impact on the system. Because they will be constrained to use renewable energy sources, net metering applications in Nova Scotia could be eligible for emissions credits or allowances under a program to reduce air emissions in Nova Scotia, or under climate change initiatives. It might not be practical for net metering applications to get these credits, because of the requirement for certification and its cost relative to the small size of generator.

Recommendation 61

The EMGC recommends that the host distributor be entitled to any emissions credits or allowances arising from the use of renewable energy sources to generate power in connection with a net metering installation.

COGENERATION

Definition of Cogeneration (Sect. 8.3)

Recommendation 62

The EMGC recommends that, for public policy purposes in Nova Scotia, facility would be defined as a cogeneration facility if:

- The facility qualifiesfor treatment under Class 43.1 of the Income Tax Act and produces electricity and usable heat; or
- The facility "contains a process that uses heat derived from combustion for the purpose of generation of electricity and other efficient uses of the mechanical or thermal energy, such as process heating, district energy systems, heat absorption chillers, space heating, etc; and
- has an overall thermodynamic efficiency of 57% as calculated by the formula below, and dedicates a minimum of 15% and maximum of 70% of its system energy output to the generation of electricity; and
- will anchor a natural gas transmission line to an area or region of the Province of Nova Scotia not then served by gas transportation infrastructure

Recommendations to Enhance Market Access (Sect. 8.5)

Recommendation 63

The EMGC recommends that electricity generated by all cogeneration facilities in Nova Scotia connected to the transmission grid can be sold under bilateral contracts to all retail customers connected to the transmission grid.

Recommendation 64

The EMGC recommends that any seller offering electricity from cogeneration, using facilities constructed in Nova Scotia after 2001, be able to sell directly to all electricity customers, other than the domestic and small general classes.

Recommendation 65

The EMGC recommends that producers of electricity from cogeneration resources sell to electricity customers in Nova Scotia on the basis of physical or financial contracts, as contracting parties can and choose to do so.

Recommendation 66

The EMGC recommends that NSPI offer to buy power from cogenerators under a PPA at a rate that will represent NSPI's avoided cost for new generation and associated transmission, subject to UARB approval.

Recommendation 67

The EMGC recommends that NSPI develop a pro forma PPA, in consultation with stakeholders.

Recommendation 68

The EMGC recommends that distribution utilities with cogeneration facilities located within their systems must offer to buy power from the cogeneration facilities at their avoided cost.

Recommendations to Address Barriers (Sect. 8.6)

Recommendation 69

The EMGC recommends that the owners of all cogeneration facilities connected to the transmission grid be provided access to the transmission system under the same terms as all other generators for both transmission and ancillary services.

Recommendation 70

The EMGC recommends that the transmission charge determinants for new cogeneration self-generators be their monthly net non-coincident peak.

Recommendation 71

The EMGC recommends that the UARB develop regulations relating to the sale of heat from cogeneration facilities that:

- Protect the interests of the users of the heat, while
- Entailing reasonable administrative responsibilities for the cogenerator.

STANDARD SERVICE AND HERITAGE POOL

Identity of Standard Service Supplier (Sect. 9.2)

Recommendation 72

The EMGC recommends that the generation function of NSPI offer a cost-based standard generation service to all generation customers. Generation customers include all distribution utilities and all customers eligible to choose competitive generation supply.

Defining and Pricing Standard Supply (Sect. 9.4)

Recommendation 73

The EMGC recommends that generation charges be unbundled for all customers.

Recommendation 74

The EMGC recommends that transmission tariffs be unbundled for all transmission customers.

Mitigating Market Power (Sect. 9.6)

Recommendation 75

The EMGC recommends that NSPI offer backup supply service to competitive generators, at a price that is cost-based and regulated by the UARB.

Recommendation 76

The EMGC recommends that NSPI create a top up and spill system for cogenerators and competitive entrants, under which it buys or sells uncontracted power at a cost-based rate, as approved by the UARB.

STRANDED COSTS AND EXIT FEES

Calculating Stranded Costs (Sect. 10.4)

Recommendation 77

The EMGC recommends that a customer be assumed to create the possibility of stranded costs only when it takes a deliberate action to reduce its load through the procurement of generation supply from an alternative source or the development of a new self-generation project, unless such action does not raise the total supply above the line in the cogeneration opportunity graph shown in section 8.2.

Recommendation 78

The EMGC recommends that stranded cost recovery be based on the load of the exiting customer at the time of notification of exit.

Recommendation 79

The EMGC recommends that stranded costs be defined as the amount of the reduction below book value of generation or transmission assets caused by the exit of a customer.

Recommendation 80

The EMGC recommends that the reduced value be calculated as the difference in estimated net present value of the stranded assets.

Recommendation 81

The EMGC recommends that stranded cost recovery be based on costs of all resources to meet NSPI supply obligations to the exiting customer. Such costs would include generation and transmission costs.

ENERGY EFFICIENCY

Recommendation 82

The EMGC recommends that the government of Nova Scotia maintain information programs to help users implement energy efficiency. The programs should be coordinated with those of other governments, wherever possible.

Recommendation 83

The EMGC recommends that the province not implement a systems benefits charge or other general funding mechanism which requires electricity customers to pay for energy efficiency programs.

REGULATOR ROLES AND MARKET SURVEILLANCE

Market Monitoring and Surveillance (Sect. 12.2)

Recommendation 84

The EMGC recommends that the transmission provider have the authority and responsibility to monitor for breaches of the market rules, to document such breaches, and to impose such penalties as are allowed under the rules.

Recommendation 85

The EMGC recommends that the UARB be given the authority and responsibility to

- Resolve disputes between parties under the tariff or market rules
- Receive and act on appeals from decisions of the transmission provider
- Review the performance of the transmission provider.

Recommendation 86

The EMGC recommends that the UARB be given authority to grant interim or temporary relief, where appropriate, in disputes between parties under the tariff or market rules.

Recommendation 87

The EMGC recommends that the UARB have the following authorities and responsibilities:

- Instruct the transmission provider on data to be sent to UARB for market surveillance;
- Perform market surveillance for abuses of market power;
- Power to initiate investigations and to respond to complaints of the abuse of market power or of abuse of monopoly position in respect of the transmission system;
- Oversee the transmission provider in its role as market monitor.

Making Market Rules (Sect. 12.4)

Recommendation 88

The EMGC recommends that rules and procedures to implement the electricity market in Nova Scotia be developed by the Department of Energy, with input from stakeholders as it determines.

Licensing Retail Sellers of Electricity (Sect. 12.5)

Recommendation 89

The EMGC recommends that all retail sellers of electricity or related products be licensed by the UARB or the Department of Energy. The licensor will set and enforce standards of conduct, including a system of monitoring the retail sellers.

Appendix D

Glossary

Agent

Buys or sells on behalf of trader.

Aggregator, Broker, Marketer, Agent & Trader

A profit-motivated entity that acts as an intermediary in arranging transactions between, or on behalf of, generators and customers. It may assemble load or generation into larger blocks (aggregator), act as a negotiator between buyers and sellers (broker), or buy, sell and take physical positions in the marketplace (marketer).

Ancillary Services

Ancillary services are those services necessary to support the transmission of energy from resources to loads while maintaining reliable operation of the transmission system. Ancillary services typically include operating reserves, regulation and frequency imbalance, scheduling, control and dispatch, and voltage support and control. FERC Order 888 named energy imbalances as an ancillary service.

Available Transfer Capability (ATC)

A measure of the remaining physical capability in a transmission network for commercial activity, over and above that already committed to users. Already committed uses would include commitments for both system reliability and commercial transactions.

Backup Supply Service

The provision of capacity and energy to a market participant, either when needed to replace the loss of its generation sources, or to cover that portion of demand that exceeds the generator=s capacity to supply for more than a short time.

Baseload Capacity

That category of generating capacity, because of its low operating costs, tends to operate continuously and steadily. Its output is generally not varied to follow changes in demand

Bilateral Contract Market

A market with direct contracts between buyers and sellers to obtain generation and/or ancillary services of a given type, duration, timing and reliability over a contractual term. A bilateral contract market is an alternative to using a centralized power pool or organized exchange auction to make purchases or sales of power or ancillary services.

Black Start Capacity

An ancillary service that provides a source of power to enable a Control Area to restore its system, or enables a generator to start its generating units andrestore service to its customers if local power is not available. Sometimes referred to as restoration service. NERC requires all systems operators to maintain black start capability in the event of widespread system failure.

Bus

An electrical connection point between different parts of the interconnected system, such as the connection between a generating facility and the transmission grid in a power station switchyard. Also referred to as a node.

Capability

The maximum load that a generating unit, generating station, or other electrical apparatus can carry under specified conditions for a given period of time without exceeding approved limits of temperature and stress.

Capacity

The maximum power that a generating unit, generation station, or other electrical apparatus can supply, usually expressed in megawatts.

Capacity Factor

Ratio of average generation to the capacity rating of an electric generating unit for a specific period expressed as a percentage.

Co-generator

A generating facility that produces electricity and another form of useful thermal energy (such as heat or steam) used for industrial, commercial, heating, or cooling purposes.

Congestion
The conditions under which the transactions that market participants wish to implement exceed the transfer capability of the transmission grid. Congestion usually requires the system operator to adjust the output of generators, decreasing output in one area to relieve constraint while increasing it in another to continue to meet customer demand.

Congestion Pricing
A method of pricing in which all energy bought and sold in the operator-administered spot market settles at market-based prices that account for the effects of congestion. Settlement prices are determined from the marginal cost (price) of serving an increment of load at each location.

Coincident Peak
The amount of metered demand at the time of the system peak. Monthly coincident peak is at the time of monthly peak.

Connection Asset
Any line, transformer or other piece of transmission equipment that is required to connect a generator or load to the common transmission grid. Typically, connection assets are used by only one (or a few) entities, and electrical flows are in one direction only (except for plant facility startup).

Constraint
A restriction on a transmission system, or segment of a transmission system, that may limit the ability to transmit power between, and hence to inject or withdraw power at, various locations. Constraints may be the result of physical limitations, such as the thermal limits of a transmission line or local voltage and stability restrictions, but can also include contingency limits, that assure secure operations in the event of an unexpected failure of a transmission or generation facility.

Control Area
A region on the electricity grid where supply and demand are kept in balance through dispatch by the system operator.

Cost of Service Regulation
(See Rate of Return Regulation)

Emission Reduction Credits (ERCs)

This is a means to quantify the avoidance of specific emissions. Credit trading allows the market forces of supply and demand to help reduce harmful pollution caused by the burning of fossil fuels. Credit allowances or quotas, will be set by individual governments, based on target agreements. Companies that have surplus emission credits can sell then to another that has exceeded its quota. An emissions credit is measured in metric tons (mt) of carbon dioxide equivalent (CO_2e).

Decommissioning

The act of permanently removing a facility from service. In the case of a nuclear plant this includes safely closing, and possibly dismantling (or otherwise disposing of) the existing facilities at the end of their service life.

Demand Side Management (DSM)

Measures undertaken to control the level of energy usage at a given time, by increasing or decreasing consumption or shifting consumption to some other time period. Consumers, utilities or third parties can undertake DSM efforts.

Direct Load Control

Refers to program activities that can interrupt consumer under direct control of the utility system operator. This type of control usually involves residential consumers. Direct Load Control excludes Interruptible Load and other Load Management effects.

Dispatch

The process by which the System Operator directs the real time operation of a supplier or a purchaser to cause a specified amount of electric energy to be provided to or taken off of the system. Dispatch control includes instructions to synchronize, desynchronize, increase or decrease electrical output and any other instruction relevant to maintaining system security.

Dispatchable Demand

Customer demand that can be adjusted in response to dispatch directions from the System Operator.

Embedded Generation

Generation that is not directly connected to the transmission grid, and is usually within a distribution system.

End-use Consumer or Customer

A residential, commercial, or industrial customer in the energy marketplace who buys energy for its own consumption and not for resale.

Energy Efficiency

Using less energy/electricity to perform the same function. Also refers to programs designed to use electricity more efficiently — doing the same with less.

Energy Imbalance Service

Provides correction for any hourly mismatch between a transmission customer's energy scheduled and actually received.

Energy Service Company

An organization that contracts with energy users, their agents, and utility companies, to evaluate, design and install capital and operating improvements to an existing building facility or industrial process, to reduce energy and operating costs over a contract period.

Enforceable

With reference to agencies being charged with monitoring and enforcing the Market Rules and protocols the agency must have the power to impose sanctions on market participants who violate the Market Rules and the process of investigation of breaches of Market Rules and protocols must be transparent.

Fairness

With reference to the market design in relation to participants and category of participants the market design should not artificially discriminate. In addition actions taken to enforce the market rules should follow written rules and protocols.

FERC

Federal Energy Regulatory Commission. Federal counterpart to state utility regulatory commissions in the United States that regulates the price, terms and conditions of power sold in interstate commerce and regulates the price, terms and conditions of all transmission services. FERC's Order 888, issued in 1996, defines the requirements under which regulated monopolies and power pools must provide non-discriminatory access to participants engaging in wholesale transactions.

Financial Bilateral Contract

A form of agreement between two parties to trade electricity at a price determined by the parties. Also known as a Contract for Differences.

Firm Transmission Service

Point-to-point transmission service that is reserved and/or scheduled that is of the same priority as that of the transmission provider's firm use of the system.

Generator

An entity that owns and operates an electricity generation facility.

Governance

The process and structure used to direct and manage the business and affairs of a corporation with the objective of enhancing shareholder value, which includes ensuring the financial viability of the business.

Green Energy

Electricity produced from renewable resources such as wind, water, biomass or solar energy. It is marketed to customers as an environmentally superior energy choice and delivered to the electricity grid, where the amount sold displaces an equal amount normally supplied by traditional fossil fuel generation.

Greenfield Investments

Investments in new generation or transmission facilities that are located on new sites, rather than at sites with existing facilities.

Green Tag

Term used to describe the environmental attributes associated with renewable energy generation. It represents the avoided emissions generated from fossil fuel and has a separate value from commodity electricity.

Gross Load

Within a distribution system, the total load, including that served by embedded generation.

Heritage Facilities

The physical electricity supply system in existence at the time of electricity restructuring. These physical facilities were acquired under a regime in which the owner was effectively granted a regulated rate of return. It can be argued that the benefit, if any, these facilities have after a move to a competitive market should belong to the customers, not to the owners, since the customers ultimately bore the risk.

Incumbent Utility

The existing utility that serves customers, and in some instances may benefit from its existing customer relationships.

Independent System Operator (ISO)

A system and market operator, who is independent of other market interests, i.e., has no ownership interest in the transmission facilities and no vested interest in specific market outcomes.

Integrated System

The electric system encompassing generation, loads, transmission and distribution facilities.

Interface

The set of transmission interconnections between any two regions.

Intermittent Power Source

A generator, such as a wind turbine, whose output may vary considerably over short periods due to the variability and unpredictability of its external energy source.

Intertie

A transmission line that connects two adjacent control areas, or a metered interconnection between two independently controlled transmission systems.

Interruptible Load

Arrangements made between consumers and the System Operator in which the consumer agrees to shed load at the direction of the System Operator, in exchange for compensation. Customers may offer this load to the System Operator as Operating Reserve.

Interval Meter

An electricity meter that is able to record and track a customer=s electricity consumption over time so that the consumption in each unit of time can be matched with the cost of power during that period of time.

IPPs

Independent Power Producers. Generators owned by entities other than an electric utility.

ISO (Independent System Operator)

A system and market operator, who is independent of other market interests, i.e., has no ownership interest in the transmission facilities and no vested interest in specific market outcomes.

Kilowatt-hour (kWh)

A standard unit for measuring electric energy, equivalent to one thousand watts used in one hour.

kWh Metering

Metering capable of measuring the total usage or flow of kilowatt-hours on a continuing basis, but not capable of recording and tracking such usage over shorter intervals, such as every hour.

LBMP

Location-based marginal pricing. (see LMP)

LDC

Local Distribution Company. An entity that owns a distribution system for the local delivery of energy to end use consumers.

Least-Cost Dispatch

The scheduling of power production as demand for electricity varies, according to the lowest cost generation sources available to the System Operator, given transmission limits and other constraints.

Light-Handed Regulation

A streamlined regulatory method designed to speed up the process and reduce the cost while balancing the interests of the various parties and allowing the regulator to carry out its statutory duties.

LMP

Locational marginal pricing, or locational pricing. A form of pricing that determines the price of energy at locations on the grid as the marginal cost of serving an increment of load at those different locations.

Load

The amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy consuming equipment of the consumer.

Load Profile

An approximation of the amount of energy typically taken during each hour by a consumer or class of consumers over a defined period, such as monthly, given the total amount of energy metered for that defined period. Load profiles are needed for consumers who do not have interval meters, and are used to allocate total kWh usage over the month to each hour, in order to perform settlements that are based on hourly prices.

Load Shedding

The process by which the system operator deliberately removes (either manually or automatically) preselected customer demand from the power system in response to an abnormal condition to maintain the integrity of the system and minimize overall customer outages.

Loop Flow
Unscheduled flow that arises from the physical nature of electricity whereby it follows the path of least impedance. Loop flow occurs on transmission paths other than the path contracted for by transacting parties. Also referred to as parallel path flow.

Losses
The energy that is consumed (lost) in the transmission and distribution of electricity from generation to load.

LSE
A load-serving entity. Historically, electric utilities that had an obligation to serve consumers. An LSE can be distribution utility if it supplies energy in addition to wires services and competing entities that take on a contractual obligation to serve retail consumer.

Market Concentration
A measure of how market share is distributed among competing firms

Market Model (Wholesale)
A theoretical description of the structure and functions of a wholesale electricity market.

Market Participant
Any entity that is authorized by the market rules to produce, buy, sell, trade, or transmit energy and/or ancillary services.

Market Power
The ability of a seller, or group of sellers acting in concert, to profitably maintain prices above competitive levels for a significant period of time.

Market Power Mitigation
The means by which a firm's ability to exercise market power is discouraged, limited or prevented.

Market Scope
Amount or share of the total electricity demand that is open to competitive supply.

Market Share
An individual firm's share of the total market sales revenues.

Market Transparency
The ability of market participants to observe and understand the workings of the market.

Megawatt (MW)
Unit of electrical power (1000kW), used to measure the generating capability capacity of a generating station or the maximum demand of an electricity consumer.

Megawatt-hour (MWh)
A measure of the energy produced or consumed over time: one megawatt of power produced for 24 hours provides 24 megawatt-hours of energy (as does 24 megawatts produced for one hour).

Merchant Generator/Plant
An electric generating facility that is built without any sales commitments.

Meters or Metering
Equipment that measures and registers the amount and direction of energy quantities over a period of time.

Monopoly
A single firm that is the sole producer of a commodity for which there is no close substitute.

Monopsony
A market characterized by a single buyer of a product. See Single Buyer Market

Native Load
The wholesale and retail customers on whose behalf the Transmission Provider, by statute, franchise, regulatory requirements, or contract, has undertaken an obligation to construct and operate the Transmission Provider's system to meet the reliable electric needs of such customers.

NEPOOL
New England Power Pool, a voluntary association of entities that are engaged in the electric power business in New England. NEPOOL has assigned responsibility for operating the markets and transmission system to an independent system operator, ISO New England.

NERC
North American Electric Reliability Council. An association of electric utilities established in 1968 in response to the 1965 blackout in the Northeastern U.S. and Ontario. Through the work of 10 regional councils and one affiliate council, NERC members ensure the reliability of the integrated North American bulk power system. NERC develops standards, guidelines and criteria for assuring system security and evaluating system adequacy, and has succeeded in maintaining a high degree of grid reliability throughout North America.

Net Coincident Peak
The amount of metered energy at the time of the system peak, net of any self-generation.

Net Energy Generation (NEG)
For a net metered application, the amount by which generation exceeds demand in a given time period.

Net Metering
A policy that allows approved customers to offset the amount of electricity required from a utility with their own renewable generation. The policy should outline interconnection and metering requirements, treatment of any excess energy produced, size of equipment capacity and other relevant aspects.

Network Integration Service
Transmission service that allows a transmission customer to integrate, plan, economically dispatch, and regulate its network resources to serve its network load in a manner comparable to that in which the transmission provider utilizes its transmission system to serve its native load customers. Network Integration Transmission Service also may be used by the transmission customer to deliver non-firm energy purchases to its network load without additional charge.

Network Transmission
All transmission facilities 69kV and above, except those radial circuits with uni-directional flow (serving single customers, single generation facilities, or distribution substations).

Non-Discriminatory Access
The rules that assure that all market participants have access to the market, the transmission system, distribution systems and ancillary services under the same terms and conditions, with no preferential treatment for those entities who may own, or be affiliated with the owners of, transmission system or distribution system assets.

Non-Firm Transmission Service

Point-to-point transmission service that is scheduled and paid for on an as-available basis and is subject to interruption.

Non-Utility Generators

See IPPs

NPCC

Northeast Power Coordinating Council, one of 10 regional reliability councils of NERC, with membership from the five control areas: New York, New England, Ontario, Quebec and the Maritimes

OASIS (Open Access Same-Time Information System)

The information system and standards of conduct contained in Part 37 of the Federal Energy Regulatory Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS. The OASIS will provide information by electronic means about available transmission capability for point-to-point service and will provide a process for requesting transmission service. OASIS will enable Transmission Providers and Transmission Customers to communicate promptly requests and responses to buy and sell available transmission capacity offered under the Transmission Provider's tariff.

OATT (Open Access Transmission Tariff)

The terms and conditions of OATTs were established by FERC Order 888. The primary objective of an OATT is to ensure that transmission service providers offer transmission service to others under equivalent terms and conditions as it provides such service to itself and its affiliates.

Option

A contract that gives the right, but not the obligation, to buy a commodity or asset for a fixed price at, by, or before a specific date.

Peaking Capacity

Generating capacity typically used only to meet the peak demand, the highest demand for electricity during the hours of highest daily, weekly or seasonal loads. Peaking capacity is typically provided by hydroelectric generators or gas-fired combustion turbine generators.

Peak Load/Peak Demand

The electric load that corresponds to a maximum level of electricity demand in a specified time period.

Physical Bilateral Contract

An agreement between two parties to trade a specified quantity of electricity at a price determined by the parties. One of the parties will schedule with the system operator for the delivery into the system at a fixed point (or points) and withdrawal from the grid of a corresponding amount at a fixed point (or points).

Point-to-Point Service

Point-to-point service provides a customer the ability to use only that portion of a transmission owner's integrated facility to input power at a specified point and take out the power at a specified point regardless of actual flow.

Power Marketers

Business entities engaged in buying and selling electricity, but which do not own generating or transmission facilities.

PPA (Power Purchase Agreement)

An agreement that set forth the terms and conditions for the sale of power.

Projected Marginal Energy Cost

The estimated amount that has to be paid for the next increment of product or service. The marginal cost of electricity is the price to be paid for kilowatt- hours above and beyond those supplied by available generating capacity.

Ramp Rate

The rate, expressed in megawatts per minute, at which a generator can increase or decrease its output.

Rate

The price charged for a commodity or service. Rates may be subject to regulatory approval or may be set by the marketplace.

Rate of Return Regulation

Process of regulation whereby the regulator sets rates at a level that will cover operating costs and provide an opportunity to earn a reasonable rate of return on the invested property devoted to the business. Also known as Cost of Service Regulation.

Reciprocity

A mutual exchange of privileges; FERC Order 888 requires a Transmission Customer receiving transmission service to provide comparable transmission service to the Transmission Provider on similar terms and conditions over facilities used for the transmission of electric energy in interstate or interprovincial commerce owned, controlled or operated by the Transmission Customer or its corporate affiliates.

Regulation

The oversight of a market by an administrative agency or regulator, including any intervention in the markets to set rates and other terms and conditions under which the regulated service must be provided. Traditional electric regulation attempts to put a monopoly under restraints to achieve prices (rates), output and investment levels comparable to those that would occur under a competitive market.

Regulator

An entity that, through power of law or some other legitimate means, has the authority to impose regulation.

Reliability

Reliability is considered to be one of the most important characteristics of any electricity supply and refers to the degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply.

Renewable Fuels

Renewable energy sources are those that produce electricity or thermal energy without depleting resources. Renewable energy includes solar, wind, water, earth and biomass power, and energy from waste.

Renewable Portfolio Standard

A policy that requires a minimum amount of electricity in a market to be from approved renewable sources.

Retail Market or Retail Access

A market in which electricity and other energy services are sold directly to consumers by competing suppliers. Also known as Direct Access.

Retailer

An entity that purchases electricity for the purpose of selling electricity to a consumer or acting as agent or broker for a consumer or another retailer with respect to the sale of electricity.

RFP (Request for Proposals)
A process for obtaining competing proposals from providers of a service or product.

Robustness
Robustness refers to the ability of Market Rules and protocols to function well under a wide range of market circumstances.

RPS Tags
RPS Tags are a certificate of origin utilized by certified renewable generators and LSE's to ensure that the terms of an RPS are met. In the context of Nova Scotia, RPS Tags would certify that a stipulated amount of energy was generated in Nova Scotia by a certified generator in a given month. The "holding" of the RPS stipulated number of valid tags by an LSE, regardless of whether that LSE had been a consumer of the renewable energy from that facility, would be the measure of that LSE having met the RPS requirements.

RTO (Regional Transmission Organization)
An entity independent of market participants that is responsible for the operation of the transmission system and administration of the transmission tariff. FERC's requirements for RTOs were first set forward in Order 2000.

SBC (Systems Benefits Charge)
A charge placed on electricity end users to create a fund used for various social purposes, such as energy efficiency programs or equalization of rates for rural or remote customers.

Self-Regulation
A regulatory approach whereby industry participants develop and administer the rules governing their operations, subject to appeal to a government regulator.

Single Buyer Market
A market with a monopoly buyer facing competitive suppliers. In electricity restructuring, it can be a first step towards competition from a vertically integrated monopoly utility structure. See Monopsony.

Spot Market
A market in which goods are traded for immediate or near-immediate delivery. In many electricity market designs, the market operator would operate and administer settlements for a spot market, in which suppliers could submit bids to sell and purchasers could submit offers to buy energy through a coordinated auction, with settlements based on market-clearing prices. Market participants are free to use the spot market to sell/purchase energy at market-clearing prices, as needed.

Spot Market Prices

The market-clearing prices determined in a spot market and used as the basis for settlements for all purchases and sales in that spot market.

Stand-by Charge

A charge imposed on a transmission customers to have access to the grid and the generation and ancillary services provided by the grid. Traditionally, stand-by charges have been imposed on customers who relied on the grid only intermittently, on a stand-by basis.

Stranded Costs/Investment

Costs that cannot be recovered from market prices. With respect to electricity competition, stranded investments are those assets owned by a utility that would become uneconomic in a competitive market.

Strike Price

With reference to bilateral contracts, the price at which parties to the contract have agreed to trade and to settle their transactions.

Substation

Facility equipment that switches, changes, or regulates electric voltage.

System Operator

The entity with the responsibility to monitor and control an electric system in real time. (The term can also refer to the individual at an electric system control centre who is monitoring and controlling the electric system in real-time).

System Losses

Percentage of kWhs delivered to the electrical grid system that were not ultimately billed to a customer. Losses can be due to line or transformation losses, errors in billing, billing estimates or theft of power.

Tariff

The terms and conditions under which a service or product will be provided, including the rates or charges that users of service or product must pay. Tariffs are usually proposed by the service or commodity provider, and are subject to regulatory approval. Typically, the rates and terms for obtaining transmission service are set forth in a tariff.

Time-of-Use Meter
A meter capable of measuring and recording the amount of electricity used during defined set periods for which specific tariffs for electricity consumption are applicable, such as daytime peak, nighttime off-peak, winter, summer.

Trader
Buys or sells on own account, but generally does not take delivery.

Trading Period
The time period in the marketplace for which physical trades are defined. The trading period for most short-run electricity markets is an hour or half-hour. All bids, offers, nominations must be defined in terms of the trading period (e.g. half-hour, hour etc.). Each trading period has its own schedule and dispatch, as well as its own market-clearing price and settlement.

Transformer
Apparatus which increases or decreases the voltage (the pressure, as opposed to the current strength) at which electricity flows.

Transmission
The movement or transfer of electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers, or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution to the consumer.

Transmission Services
The acceptance, transmission and delivery of power within a Control Area. May include specific ancillary services.

Transmission Tariffs
The authorized charges levied for provision and use of transmission services.

Transparency
Transparency refers to the degree with which the market rules and protocols are simple enough to fulfill the goals of market efficiency and market function. In addition, under this principle actions by the market operator and system operator should be capable of audit and verification and market information should be available to all market participants on a timely basis.

UARB

The Nova Scotia Utility and Review Board.

Unbundling

The breaking down of a bundled service into its component parts so that a customer can choose to purchase different components of the service from different parties. When LDCs offered only bundled services, their customers could purchase electricity only from the LDC. In an unbundled environment, the customer can choose to purchase its electricity supply from any supplier it wants and the LDC provides delivery to the customer's meter. Additional unbundling may allow other parties to provide other components of service, such as billing, meter reading, and credit and collection services.

Vesting Contracts

Contracts that are entered into prior to the start of a new market. Typically vesting contracts are used to assure that the benefits (or costs) of key resources owned by the incumbent utility are captured by (or imposed upon) consumers for some defined period after competition begins.

Wheeling

The use of an interconnected transmission system to implement electricity transactions that transmit power into (wheeling in), within, out of (wheeling out) or through (wheeling through) that system.

Wholesale Market

This refers to the market in which electricity and other energy services are sold towholesalers/retailers/distributors (who in turn sell to retail or end-use customers). A wholesaler/retailer/distributor of power would have the option to buy its power from a variety of generators or suppliers, and the generators or suppliers would be able to compete to sell their power to a variety of wholesalers/ retailers/distributors.

Wholesale Pool Market

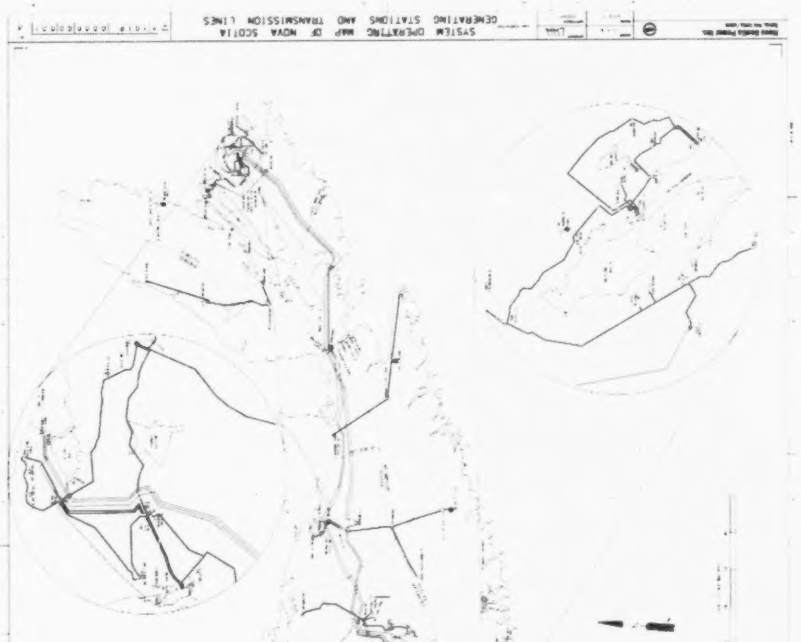
Term used to refer to a security-constrained least-cost generation dispatch coordinated by the system operator, based on bids to sell and offers to purchase submitted by market participants, and the associated settlement system.

Zonal Pricing

A form of LMP in which the price for electricity is determined for specific regions or zones (as opposed to points or nodes) of a transmission system.

Appendix E

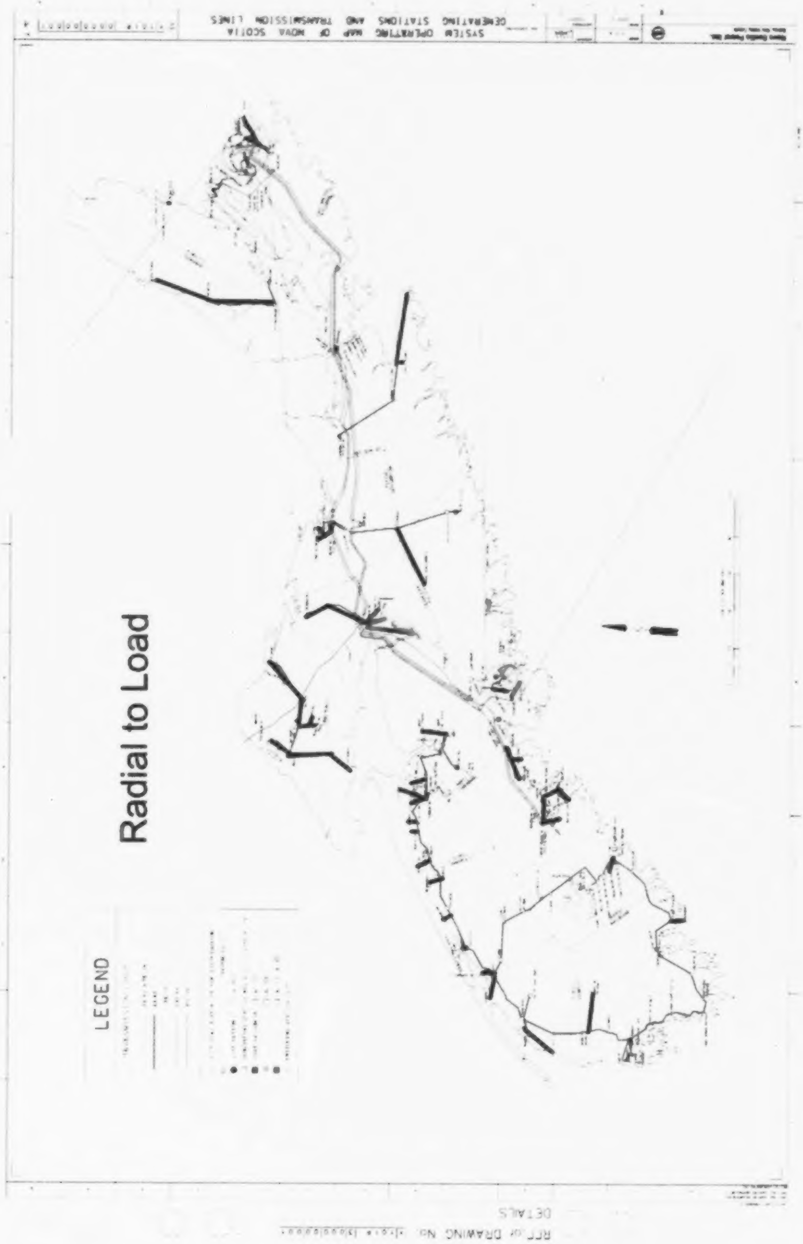
NSPI Transmission Lines



SYSTEM OPERATING MAP OF NOVA SCOTIA
GENERATING STATIONS AND TRANSMISSION LINES
LEGEND
DETAILS
REF. or DRAWING No.

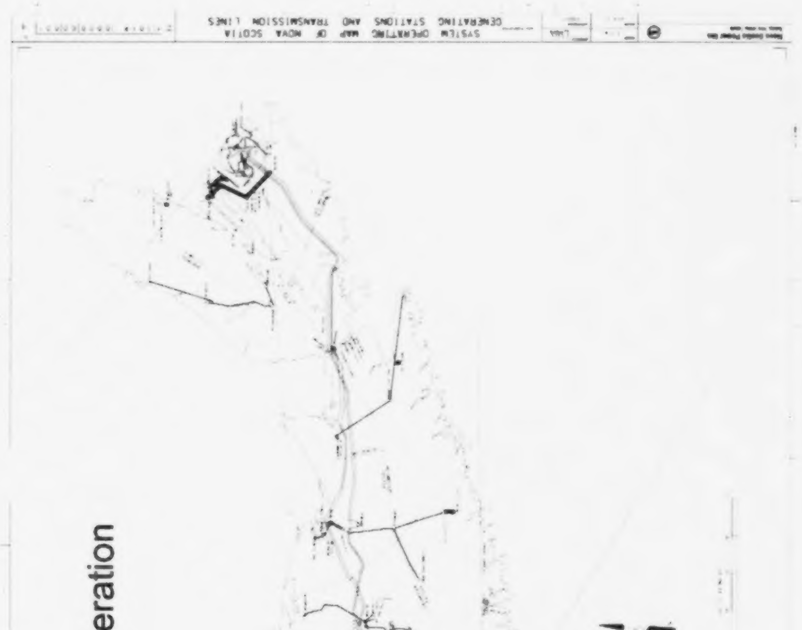
Appendix F

NSPI Transmission Lines – Radials to Load


SYSTEM OPERATING MAP OF NOVA SCOTIA
GENERATING STATIONS AND TRANSMISSION LINES
Radial to Load
LEGEND
REF. or DRAWING No.
DETAILS

Appendix G

NSPI Transmission Lines – Radials to Generation


SYSTEM OPERATING MAP OF NOVA SCOTIA
GENERATING STATIONS AND TRANSMISSION LINES
Radial to Generation
LEGEND
DETAILS
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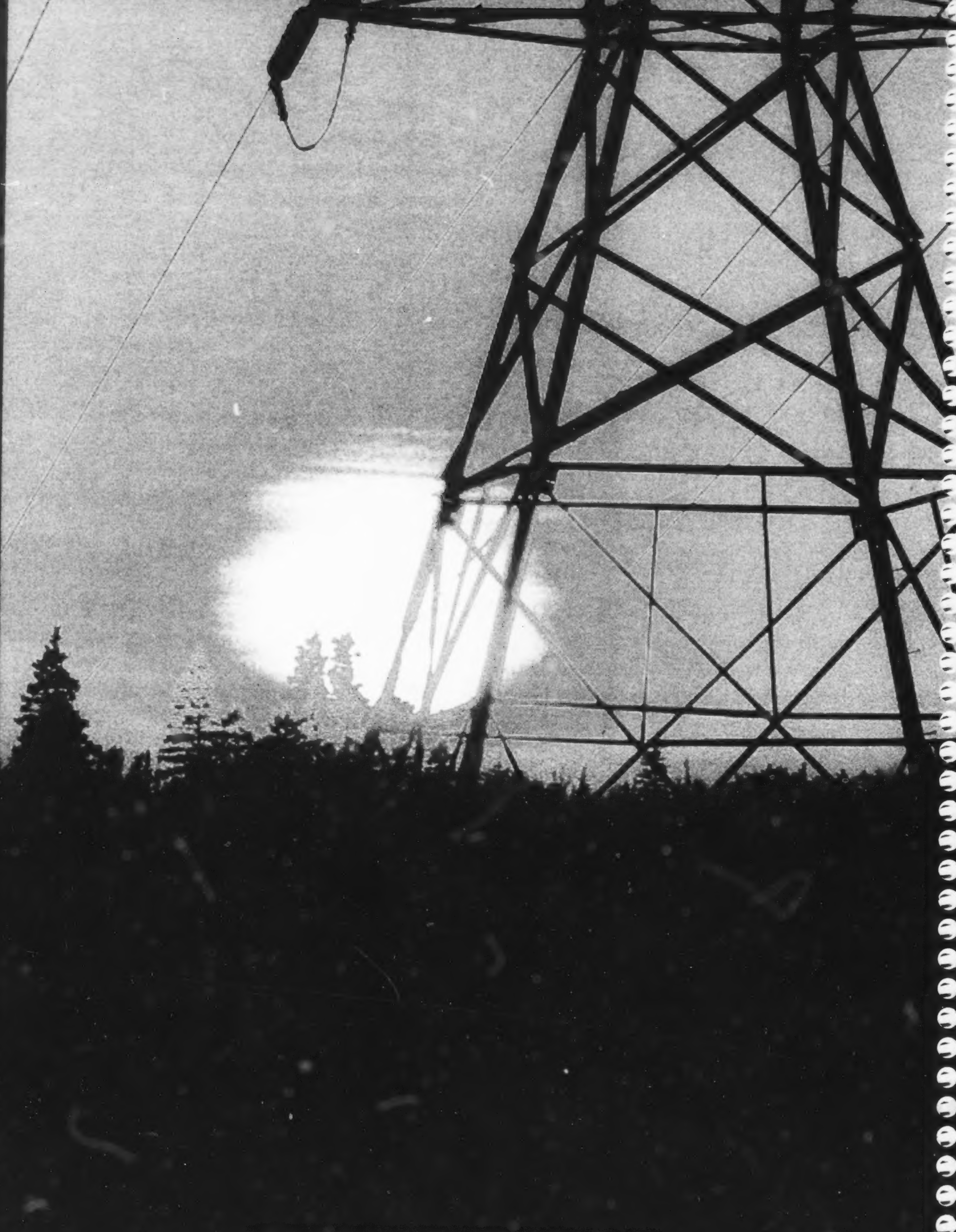

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